

# ELECTRIC FEDERALISM

POLICY FOR ALIGNING  
CANADIAN ELECTRICITY  
SYSTEMS WITH NET ZERO

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# INTRODUCTION

## 01

## *Aligning Canadian electricity systems with net zero*

### **A focus on electricity**

**systems:** *In this report, we are using electricity systems as an overarching term to refer to the various networks of infrastructure, institutions, and players involved in the supply of electricity in Canada. This includes those participants involved in generation, transmission, and distribution, as well as market operators. Our definition extends to the demand side only insofar as shifts in the timing and extent of demand effectively act as alternative sources of supply. And we've employed the plural form, systems, to acknowledge that Canada does not have a single electricity system but rather numerous regional systems, which are primarily managed at the provincial and territorial levels.*

The path to net zero in Canada depends on expanding the supply of clean electricity in every province and territory. Transforming Canadian electricity systems to align with net zero—specifically by growing them to support greater use of electric technologies, shifting to non-emitting electricity sources, and phasing out unabated fossil fuel ones—will support Canada's target of achieving a net zero electricity system by 2035 and underpin broader decarbonization efforts across the country. Only changes in government policy can drive this transformation at the speed necessary to achieve Canada's climate goals.

This is the second of two reports on transforming electricity systems in Canada to meet emissions reduction targets and address climate change. In the first, *Bigger, Cleaner, Smarter: Pathways for aligning Canadian electricity systems with net zero*, we looked at what changes will be required, specifically identifying three crucial transformations—growing bigger, getting cleaner, and becoming smarter.

In this report, we turn our focus to how to address the main challenges that policy makers, utility operators, system planners, and regulators will face in pursuing these changes. Our objective is not to paint a precise picture of every challenge facing each electricity system transformation or to supply the full suite of policies required for electricity systems to support net zero. Instead, we've identified the main challenges and corresponding policy interventions that must be considered to drive these transformations.

**Defining net zero:** *The federal government has set an economy-wide target of net zero emissions for Canada by 2050 and a target of achieving a net zero electricity grid by 2035. Several provinces and territories have also set their own emissions reduction targets. Achieving all of these goals requires reducing emissions as close to zero as possible, while removing any remaining emissions from the atmosphere and storing them permanently. Simply put, Canada must take as many emissions out of the atmosphere as it puts in. Reaching Canada's national goal, however, does not necessarily mean that every province and territory must achieve the same net zero target—negative emissions in one province or territory could potentially be used to offset remaining emissions in another.*

Notably, this report focuses on the *supply* of clean electricity rather than policy to increase end-use electrification (such as expanding the deployment of demand-side technologies like electric vehicles and heat pumps). We do also consider electricity demand, however, insofar as greater demand flexibility can allow it to act as an effective source of supply at times.

Each province and territory in Canada has its own electricity system, so the policies required to transform them must account for these different starting points (see Box 1 for an overview of these differences). Still, all systems face a similar set of core challenges.

This report identifies four key policy challenges facing electricity systems transformation in Canada. First, federal climate policy for electricity systems is misaligned with net zero. Second, provincial policies and institutions are not sufficiently coordinated. Third, necessary investments in new and existing electricity infrastructure could lead to upward pressure on rates. And fourth, provinces and territories lack incentives to enhance interregional integration.

Overall, we find that transforming Canadian electricity systems to support net zero goals requires an approach we refer to as *electric federalism*, which includes policy interventions from federal, provincial, and territorial governments. Provinces can take considerable policy leadership, since they control many of the key policy levers. And the federal government, for its part, can play an important enabling and accelerating role. This report provides policy advice for both orders of government on how to pursue an effective coordinated approach to electricity systems transformation.

This report is structured as follows. Section 2 outlines what's at stake in transforming Canadian electricity systems to support net zero goals. Section 3 outlines four key challenges that governments, utilities, system planners and regulators will face in trying to enable and drive this transition. It also discusses available policy responses and their pros and cons, and identifies preferred solutions. Section 4 outlines how governments can set policy for electricity sector transformation that will work in the Canadian federation. Finally, Section 5 provides recommendations to provincial and territorial governments and to the federal government.

**BOX 1.***Canada's electricity landscape*

Canadian electricity systems differ significantly from region to region, both because electricity falls within provincial and territorial jurisdiction and because there are substantial variations in the endowment of natural resources. Each province also has its own electricity regulator, which operates under provincial laws and oversees regulated transmission and distribution rates—including in Alberta and Ontario, where some generation and retail sales of electricity are open to competition.

Electricity market structures vary further in terms of their degree of vertical integration,<sup>1</sup> their ownership, and their degree of competition, creating three broad marketplace categories across the country:

- 1. Vertically integrated Crown corporation with little wholesale and retail competition.** This is the most common market structure, found in British Columbia, Saskatchewan, Manitoba, Quebec, New Brunswick, and Nunavut. Under this structure, the provincial or territorial government owns the dominant power company (a Crown corporation), which is in charge of generation, transmission, system operation, distribution, and retail. This structure nevertheless allows other players to supply electricity in some regions, including independent power producers (IPPs) and municipal, cooperative, and private distribution companies. Competition occurs in the wholesale market through long-term contracts between IPPs and the distribution division of the Crown corporation. The retail market is closed to competition, so customers have no choice other than the regulated tariff offered by the distributor, under the oversight of the provincial regulator. Newfoundland and Labrador, the Northwest Territories, and Yukon differ slightly, with both Crown corporations and investor-owned utilities involved in the market. In Newfoundland and Labrador, electricity generation and distribution is provided by two utilities—Newfoundland and Labrador Hydro, a Crown corporation, and Newfoundland Power, an investor-owned utility and subsidiary of Fortis Inc. Similarly, in Yukon, two regulated utilities generate and distribute electricity—Yukon Energy Corporation, the territory's public utility and ATCO Electric Yukon, an investor-owned utility. In the Northwest Territories, the government-owned Northwest Territories Power Corporation produces and supplies electricity to most of the territory's communities and also supplies electricity to Northland Utilities, an investor-owned utility that distributes electricity to consumers through two subsidiaries.

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1. Vertical integration refers to the extent to which the same organizations are involved in the generation, transmission, system operations, distribution, and retail activities of the sector.

- 2. Vertically integrated private company with little competition.** This market structure is found in Nova Scotia and (partially) in Prince Edward Island. In Nova Scotia, a single investor-owned company is responsible for the province's electricity sector, with some supply contracts from IPPs and generators outside of the province. In P.E.I., a vertically integrated, investor-owned company supplies electricity to most customers. Most of the electricity used in P.E.I. comes from outside the province, but generation on the island (predominantly wind) is shared between IPPs and a relatively new, provincially owned corporation (PEI Energy).
- 3. Unbundled electricity sector with open wholesale market and retail competition.** This is the structure in Alberta and (partially) in Ontario, which reformed their electricity sectors in 1996 and 2002, respectively. Generation activities are carried out by both investor-owned and municipally owned companies, as well as a Crown corporation in Ontario. While Alberta remains fully committed to a competitive wholesale market, Ontario has pursued a hybrid market structure. Ontario Power Generation's nuclear and hydroelectric stations are rate-regulated and the government has signed long-term contracts with independent generators, which have varied in terms of the level of competition in their procurement processes. In both provinces, most transmission assets are owned by investor-owned companies. System operations are under the control of a non-profit organization set up by the province—the Alberta Electric System Operator (AESO) and Ontario's Independent Electricity System Operator (IESO). The IESO also has responsibilities in planning, conservation, procurement, and marketplace design—responsibilities which are not usually assumed by system operators. Distribution is predominantly under the control of municipal companies in both Alberta and Ontario, offering regulated retail options that competitive retailers can challenge in an open market.

In all of Canada's electricity markets, costs from all activities—generation, transmission, system operations, distribution, and retail services—are recovered (to varying degrees) through the price customers pay. Tariffs are structured using three main components:

- A **fixed charge**, per day of service, regardless of the amount of energy used and peak demand.
- An **energy charge**, or volumetric charge, based on the amount of energy used in a given period (usually per month).
- A **demand charge**, or power charge, based on the peak demand use (in kW or kVA) during a given period, or based on a subscribed level of service.



Depending on how each jurisdiction defines its rates, all of these components can vary by hour, day, or season. In practice, however, they are mostly constant across time, except in Ontario, where time-of-use rates are the default (with a choice of those rates or tiered pricing for residential and small business customers). Regulators usually design rates for residential customers using only a fixed charge and an energy charge. Rates for commercial and industrial customers usually have all three components, including a demand charge.

*Sources: Pineau 2021; Senate of Canada 2015.*

# WHAT'S AT STAKE

# 02

## *What's at stake in transforming Canada's electricity systems*

The decisions Canadian governments make in the process of transforming Canada's electricity systems to align with net zero have high stakes. Getting it right—or wrong—will have big implications well beyond the electricity sector. Ultimately, to earn broad, sustained support, policies to support electricity system transformation must not only consider net zero goals, but also broader social objectives. This requires policies that are both effective and cost-effective, that enable clean growth opportunities, that advance justice and equity, and that catalyze Indigenous leadership and participation.

### *Transforming Canadian electricity systems is a critical early step on the path to net zero*

The transformation of Canada's electricity systems to align with net zero represents a crucial early step toward meeting Canada's climate goals. Some of the most important elements of this transformation include expanding the supply of non-emitting electricity and enabling electrification of major energy users such as passenger vehicles, heavy industrial processes, and space heating for buildings (McPherson 2021). Taking these early steps in a timely way will unlock many other decarbonization opportunities throughout the Canadian economy. Decisive policy action and strong investments today can ensure Canadian electricity systems continue to deliver reliable, affordable service while they position themselves to best support Canada's net zero transition.

Without these timely first steps, Canadian electricity systems would continue to be a source of emissions, which would hinder decarbonization progress in other sectors, making net zero goals much harder to reach. And beyond these decarbonization objectives, failure to prepare Canadian electricity systems for evolving energy needs and worsening climate impacts could result in systems that are costly or unreliable.

### *Acting early and wisely can reduce the costs of the transformation*

The question of costs is central to policy support for the transformation of Canada's electricity systems, and multiple studies have reached the same conclusion: acting early with smart policies can significantly reduce the overall costs.

Three key findings regarding costs emerge from studies of this transformation.

First, investment costs will rise as we transform electricity systems in Canada, so attention should be paid to their distribution to ensure that costs don't land disproportionately on some groups, notably low-income households and marginalized populations.

Second, the majority of these costs will be for capital, especially for electricity generation, transmission, and distribution infrastructure, and increasing uptake of electrified end uses. Operating and fuel costs are expected to fall significantly as systems become aligned with net zero (Langlois-Bertrand et al. 2021; EPRI 2021).

And third, acting now reduces overall costs (Bataille et al. 2015). Early and effective action allows Canada to avoid a more abrupt transition later, which would include the significant costs associated with stranded assets in the form of high-emissions infrastructure and higher consumer prices as underbuilt electricity systems struggle to keep up with growing demand. Acting now also reduces overall costs by driving innovation, which can improve the cost and availability of important technologies as well as help gain experience with their deployment and implementation. Finally, the federal government's 2035 deadline for achieving a net zero electricity system leaves no room for delay.

The cost and economic impact estimates from a range of modelling studies summarized in Table 1 were generated by models projecting cost-optimal pathways to net zero. Pursuing these pathways in practice will require effective and cost-effective policy.

*Table 1.* **Cost estimates of aligning Canadian electricity systems with net zero**

Study	EPRI (2021)	Dolter and Rivers (2018)	Langlois-Bertrand et al. (2021)
<b>Scenario</b>	Net zero emissions in Canada by 2050 (economy-wide) Models the transition to meet economy-wide net zero emissions by 2050	Zero emissions in Canada's electricity sector in 2025 A single-year model that optimizes Canada's electricity in 2025 given zero emissions constraints	Net zero emissions in Canada by 2050 (economy-wide) Models the transition to meet economy-wide net zero emissions by 2050
<b>Definition of costs</b>	Capital cost for new generation, storage, and transmission assets, and operational costs for all generation, storage, and transmission assets. Excludes fuel cost and intra-regional transmission.	Cost for generation, storage, and transmission assets, and operational costs for all generation, storage, and transmission assets. Includes fuel cost and both inter- and intra-regional transmissions and distribution cost.	Capital cost for new generation, storage and transmission assets, and operational costs for all generation, storage and transmission assets. Excludes fuel cost and inter-regional transmission and distribution cost.
<b>Cost estimates (in 2022 \$CAD)</b>	Average of \$12.9 billion per year above reference scenario from 2025 to 2050	\$13.8 billion in a single year (2025) above reference scenario; \$18.7 billion in a single year (2025) above reference scenario to 2025 without new inter-regional transmission	Average of \$15.05 billion per year above reference scenario from 2025 to 2050

## *Strategic action today can enable clean growth opportunities*

The net zero studies we reference above often exclude other critical costs and benefits of transforming electricity systems. Policies can further minimize the costs and maximize the benefits of this transformation by tackling these factors explicitly.

First, policies can reduce costs by enhancing the resilience of electricity systems, particularly with respect to climate impacts. Our report *Under Water* quantified the costs of significant climate hazards on Canada's electricity systems and found that early measures to enhance resilience—including regular maintenance for transmission and distribution infrastructure and replacing components with more resilient materials—can reduce damage costs by 80 per cent by the end of the century, as much as \$3.1 billion annually (Ness et al. 2021). Additional opportunities exist to enhance electricity system resilience, including strengthening other types of electricity infrastructure, increasing system flexibility, enhancing energy efficiency, and implementing

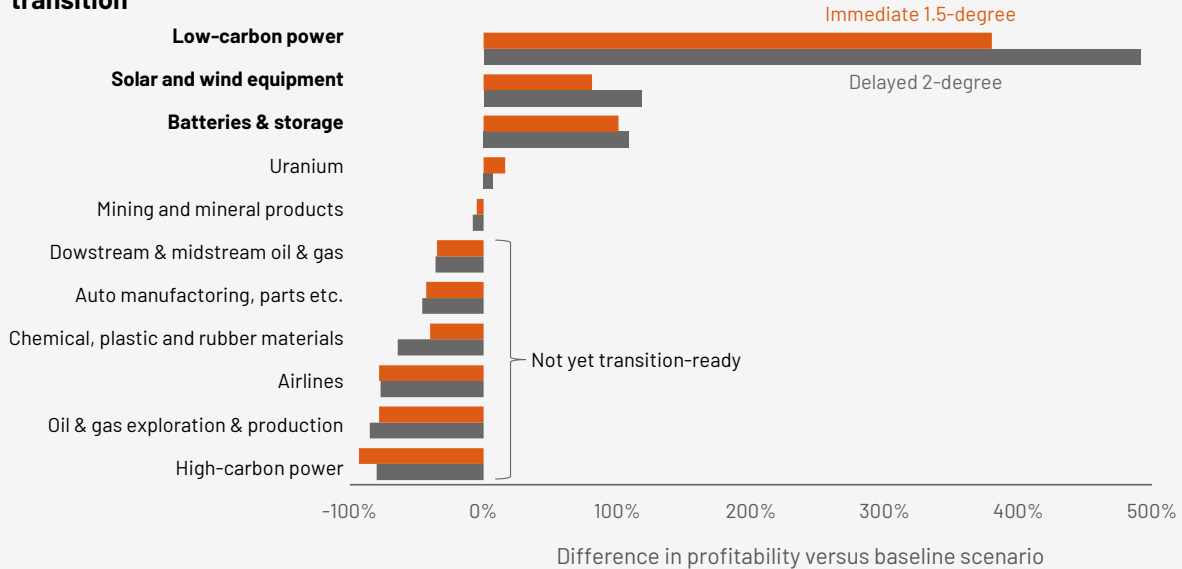
measures to support rapid response, restoration, and recovery when a climate-induced event occurs (Clark and Kanduth 2022).

Second, policies can maximize benefits by capitalizing on clean growth opportunities. In particular, moving quickly to align electricity systems with net zero can generate clean growth opportunities through the increased global competitiveness of low-carbon electricity itself, as well as the supply chains of goods that rely on it. According to our report *Sink or Swim*, Canadian companies active in low-carbon electricity, batteries and storage, and solar and wind equipment are well-positioned to grow in the global low-carbon transition (Figure 1). In addition, increased electrification could also enhance the transition readiness of emissions-intensive sectors that are globally traded, such as aluminium, steel, and metals and minerals, helping them stay competitive as global markets shift (Samson et al. 2021).

Investments to transform Canadian electricity systems will also generate employment opportunities in existing and emerging

Figure 1.

**Canadian electricity sector companies are well-positioned to profit in the global low-carbon transition**



Source: Samson et al. (2021). Notes: The figure above shows the net present value of the difference in weighted average market capitalization between the baseline scenario and two low-carbon transition scenarios for Canadian companies' international sales and operations between 2021 and 2050. Results are shown for sectors most affected by the transition, where there are more than three publicly traded Canadian companies. Low-carbon power represents the 25 per cent least emissions-intensive assets (hydroelectric, other renewables and nuclear) while high-carbon power represents the 25 per cent most emissions-intensive assets (coal and natural gas). Results for companies operating both high and low-carbon facilities are split across the categories.

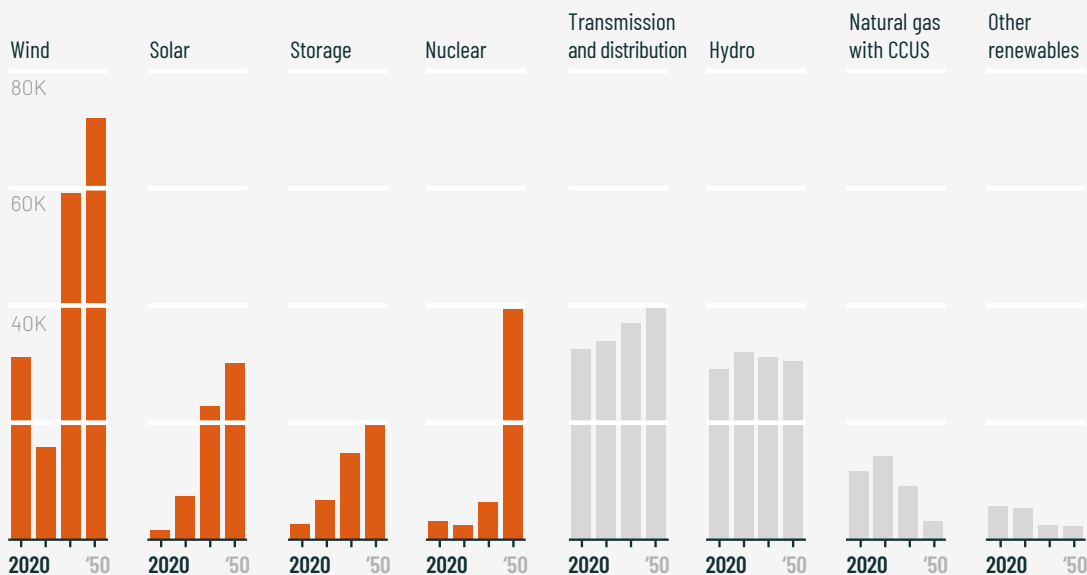
sectors. New analysis commissioned by the Institute shows that investments in electricity generation, transmission, and distribution will result in 262,000 direct and indirect jobs in 2050 (Stiebert 2022). For reference, the sector currently employs approximately 97,000 workers, so this represents nearly a tripling in employment (Statistics Canada 2021). In particular, six technologies account for more than three quarters of these employment projections—wind, transmission and distribution, hydro, solar, storage, and nuclear (Figure 2).

These changes to energy sector employment present opportunities to advance diversity and inclusion in the sector, so long as equity considerations are factored into policy making. Targeted programs can help workers from equity-seeking groups gain the necessary skills and opportunities to secure employment in the sector. For example, a paper by Indigenous Clean Energy (2022) underscores the importance of skills development, training, education programs,

Figure 2.

**On the path to net zero, renewables, storage, and nuclear\* see the most jobs growth**

Labour required (number of full time equivalent jobs averaged across studies)



Source: Stiebert (2022). \*Growth in labour required in the nuclear sector is attributed to the uptake of small nuclear reactors. There is a significant divergence between studies in the labour required to support nuclear power, due to their diverging findings around the role that small modular reactors will play in the transformation of Canada's electricity systems.

and capacity building to enable Indigenous youth and young adults to pursue careers in the sector and ultimately fill leadership positions. Finally, well-designed policies can enable cooperation with local communities, stakeholders, and rightsholders; with the broader public; and with Indigenous nations, communities, and organizations to deliver local benefits and to identify concerns and mitigate potential impacts from new electricity infrastructure projects. Building new infrastructure is vital for transforming electricity systems, so decision-makers must find ways to develop projects that take seriously the concerns of opponents. Local opposition could otherwise lead to project delays or cancellations, which could in turn increase costs. Effective tools include enhancing public participation in system planning and increasing local and Indigenous involvement in new and existing projects. If decision makers fail to build and maintain public trust in these ways, they risk raising the cost of electricity systems transformation or undermining the political viability of the larger transition altogether (Box 2).

### *If pursued with justice and equity in mind, electricity system transformations can contribute to a fairer society*

Transforming Canada's electricity systems to align with net zero presents real opportunities to improve justice and equity. But seizing these opportunities requires decision making that addresses equity considerations from the outset. Otherwise, policies and actions to enable electricity sector transformation may exacerbate existing inequalities.

Electricity system transformations require major investments at both the household and system levels, which could have a range of impacts on low-income individuals. At the household level, lower-income consumers tend to transition more slowly to new end-use electrification technologies such as electric vehicles, heat pumps, and solar PV because their higher upfront costs can be prohibitive. Because these technologies represent cost-saving opportunities, this slower transition could exacerbate economic inequalities.<sup>2</sup> At the utility level, system-wide investments in new technologies and

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2. While policy for adoption of demand-side technologies is not the focus of this report, explorations of the equity dimensions of Canada's net zero transition must consider inequities in low-income households' ability to adopt energy end-use technologies that enable fuel switching away from fossil fuels.



## **BOX 2.** *Local and public opposition to electricity infrastructure*

Our report *Bigger, Cleaner, Smarter: Pathways for aligning Canadian electricity systems with net zero* has found that achieving net zero in Canada will require meeting electricity demand that is 1.6 to 2.1 times greater than it is at present. This will require significant growth in generation facilities, transmission infrastructure, and distribution networks. This new electricity infrastructure must successfully pass through complex siting and approvals processes, the success of which depends largely on the extent to which local communities and the broader public support their development.

Local and public opposition to new infrastructure development can emerge for a variety of reasons. In the case of new transmission lines or new large-scale wind, solar, or hydro developments, local communities may oppose projects due to concerns over land use, environmental impacts, or lack of fair compensation (whether real or perceived). For example, Maine residents voted recently to stop construction of a Hydro-Québec transmission line from Quebec to New England that would have supplied as much as 1,200 MW of hydropower to the New England grid, viewing it as providing insufficient local benefits compared to the environmental cost to the state's forests (Valdmanis 2021).

Opposition can also stem from negative perceptions of a particular energy source. Public opposition to nuclear power, for example, typically arises from perceived risks to public safety. In Ontario, some wind farm projects have encountered local opposition stemming from environmental and land use concerns, perceived health risks, or dissatisfaction with project consultation and implementation (Christidis et al. 2017). And in British Columbia, the Site C Dam has faced long-standing opposition from critics concerned about environmental impacts, financial viability, and implications for Indigenous peoples.

In many cases, proposed infrastructure projects may have implications for Indigenous territory, rights and well-being. These projects must proceed in ways that respects those rights and advances reconciliation and Indigenous self-determination, in line with the United Nations Declaration on the Rights of Indigenous Peoples. Engaging and partnering with Indigenous nations is critical for ensuring that projects do not infringe on their rights or result in adverse impacts. In order to accelerate the deployment of electricity infrastructure, governments at all levels should work with Indigenous communities and organizations to mitigate their concerns and advance broader social and economic goals, including reconciliation, self-determination, energy security, and economic development.

infrastructure upgrades may increase electricity rates, with potentially disproportionate impacts on lower-income households (we discuss the potential upward pressures on rates and policy options to mitigate them in Section 3.3). Addressing inequities in households' ability to adopt electrification technologies and mitigating upward pressures on rates would not only improve economic equity but could also advance equity along other dimensions, as low-income individuals in Canada are more likely to be from marginalized communities, including recent immigrants, people with disabilities, and Indigenous people.

Finally, beyond supporting climate and economic objectives, investments in transforming electricity systems today can promote inter-generational equity by improving outcomes and reducing costs for future generations. Acting now can reduce overall system costs while improving Canada's likelihood of achieving its emissions reduction goals and limiting global temperature rise.

### *Catalyzing Indigenous participation and leadership can support Indigenous self-determination and reconciliation*

The transformation of Canada's electricity systems to align with net zero presents both opportunities and challenges for Indigenous Peoples across Canada. In particular, clean energy projects represent an opportunity for Indigenous communities to contribute to net zero goals while also advancing their own social, economic, and environmental objectives.

Communities seeking to develop clean energy projects face challenges that differ depending on the community's size, climate, and location, among other factors. Common challenges include lack of internal capacity, lack of financial resources, limited government supports and policies, and inadequate participation in key decision-making processes.

In addition, many Indigenous communities are not connected to an electrical grid or natural gas network and must produce their own energy locally, often using expensive and polluting diesel generators. These off-grid communities face additional challenges, including limited access to alternative electricity sources and end-use technologies. Many of these communities are also geographically dispersed, making it difficult for them to benefit from economies of scale, which in turn limits their ability

to access adequate capital to develop projects. And highly subsidized electricity bills can entrench reliance on existing fuels such as diesel, especially when governments and utilities have not considered the true costs and benefits of different energy sources (Lovekin and Heerema 2019). Many Indigenous communities also face other, more pressing challenges, such as securing access to clean water and suitable housing, as well as other systemic issues stemming from colonialism.

Despite these challenges, Indigenous communities, governments, and organizations across Canada have positioned themselves as leaders in Canada's clean energy transition. In the last two decades, thousands of renewable energy projects—including over 200 medium- and large-scale generation projects—have been launched with Indigenous leadership and involvement. According to Indigenous Clean Energy, the next wave of Indigenous participation and leadership in the sector will see greater clean energy diversification through new project and market opportunities (ICE 2022).

These opportunities include:

- supporting economic self-determination through Indigenous ownership (or co-ownership) of electricity projects;
- creating new, more inclusive relationships between Indigenous communities and other key players in the electricity sector, including governments, regulators, utilities, and developers;
- enhancing Indigenous participation in electricity systems planning;
- improving environmental, social, and health outcomes by accelerating the phase-out of diesel generation in northern and remote communities; and
- promoting greater inclusion in the workforce through targeted employment and training opportunities (see ICE 2022 for more details).

Simply put, Canada's electricity system transformation is creating real opportunities to advance reconciliation and Indigenous self-determination.

# KEY CHALLENGES

**3.1** Challenge A: Federal climate policy for electricity systems is misaligned with net zero

**3.2** Challenge B: Provincial and territorial policies and institutions are not sufficiently coordinated with net zero

**Box 3** British Columbia as an illustration of the need to coordinate provincial policies and institutions with climate goals

**Box 4** The role of public utilities and system operators

**3.3** Challenge C: Creating resilient electricity systems aligned with net zero could put upward pressure on electricity rates

**Box 5** Current supports and rebates for low-income households in Canada

**Box 6** Subsidizing investment costs in electricity systems causes minimal distortions to incentives

**3.4** Challenge D: Incentives for greater interregional coordination and interties are weak

**Box 7** Potential composition and focus for the federal government's proposed Grid Council

# 03

## *Key challenges and policy options for transforming Canada's electricity systems*

In this section, we analyze four policy challenges Canadian governments will encounter as they seek to align electricity systems with net zero:

- Federal climate policy for electricity systems is misaligned with net zero;
- Provincial and territorial policies and institutions are not sufficiently coordinated with net zero;
- Creating resilient electricity systems aligned with net zero could put upward pressure on electricity rates; and
- Incentives for greater interregional coordination and interties are weak.

Transforming Canada's electricity systems will surely face numerous other technical, political, and social challenges, but we have identified these four as particularly critical ones, based on literature review, stakeholder consultation, and expert input.<sup>3</sup> Left unaddressed, these challenges could significantly impede progress toward net zero goals. Addressing them, on the other hand, could generate greater support and impetus for addressing other significant challenges, some of which are noted in boxes in this report and others are discussed in our scoping papers and case studies (Hastings-Simon 2021; McPherson 2021; Pineau 2021; Shaffer 2021; Turner 2021; ICE 2022; Clark and Kanduth 2022; McCarthy 2022).

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3. See Annex for more information about our stakeholder consultations.

We define a **challenge** as a factor likely to impede progress on the transformation of electricity systems to align with net zero, but one that doesn't necessarily prevent it altogether. Overcoming a challenge may not be strictly necessary to transform electricity systems but rather would reduce friction and facilitate the achievement of the three main changes in electricity systems laid out in our companion report on technical pathways (making electricity systems bigger, cleaner, and smarter). Overcoming these challenges can also minimize costs and maximize benefits and opportunities across the stakes that we discuss in Section 2. In some cases, this may be a matter of creating a level playing field for different solutions or enabling lower-cost pathways. In others, deeper or more fundamental governance reforms would enable the larger transition.

For each of the four main challenges we have identified, we describe the nature of the challenge, identify a set of policy options to address it, outline the pros and cons of those options, identify preferred solutions, and discuss the extent to which preferred solutions do or do not complement one another. The inclusion of a particular policy option does not imply an endorsement of it; rather, we have assessed a range of options to examine their relative merits. Our assessments of the pros and cons of each policy option are intended to be illustrative rather than comprehensive. We consider a range of factors, including practicality of implementation, economic efficiency, cost, equity, speed, implications for market or incentive distortions, and overall effectiveness in addressing the larger challenge of aligning electricity systems with net zero.

This section explores the relationships across policy options *within* each challenge. Section 4 will then look across the four challenges and the policy options for addressing them to understand how they interact, what roles different orders of government can play in addressing them, and how this larger set of challenges can be addressed in a way that works in the Canadian federation.

### 3.1 *Challenge A: Federal climate policy for electricity systems is misaligned with net zero*

#### 3.1.1. The nature of the challenge

Canada has set a goal of achieving net zero emissions in the economy by 2050 and net zero for electricity generation by 2035 (announced in 2021). All orders of government have made significant progress in recent years at using climate policies (including carbon pricing, regulations to phase-out unabated coal-fired generation, low-carbon fuel standards, and zero-emissions vehicle mandates) to drive progress toward these national emissions goals—particularly the federal government's 2030 emissions reduction goal en route to 2050. Current policies still fall well short of ambitions, however, and significant gaps and challenges remain in the way such policies are applied in the electricity sector.

One of the most significant challenges is that the stringency of climate policy<sup>4</sup> in the electricity sector (as well as climate policy writ large) is not yet aligned with the new targets for 2035 and 2050. The federal government has released a plan for meeting its economy-wide 2030 target, but policy for the longer-term net zero target still remains largely undefined, and some provinces still lack emissions targets that align with net zero. And questions remain around the political durability of key emissions-reduction policies such as carbon pricing.

Another major challenge is that the existing federal carbon pricing policy for electricity systems creates insufficient or uneven signals for achieving net zero in the sector. Unlike in Alberta, where the performance benchmark applies uniformly to all power generators, the federal output-based pricing system (OBPS) uses fuel-specific benchmarks that only provide incentives to decrease the emissions intensity of coal-fired and natural-gas fired generation, rather than encouraging increased use of low- or non-emitting categories of generation in place of higher-emitting ones. The federal system creates an uneven playing field, reducing the average carbon cost for coal plants while limiting the incentive for new investment in renewable generation (Bishop 2019). While many provinces and territories have implemented their own carbon pricing systems that apply in their jurisdictions in place of the federal one, the federal system sets the minimal national stringency standards for all provincial and territorial systems and thus has implications for the effectiveness of carbon pricing systems nationwide (Sawyer et al. 2021). And while several provinces, as well as the federal government, have announced or implemented regulations to phase out coal-fired electricity, there is no such equivalent for natural gas. The federal government has committed to implementing a Clean Electricity Standard (CES) that could help address these policy gaps, but its details have not yet been proposed.

Combined, these challenges increase the risk of encouraging behaviours and investments from utilities, companies, and households that are poorly aligned with net zero goals. And because electricity planning has a time horizon of decades, policy cer-

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4. In this report, we use a narrower definition of “climate policy,” referring to policy targeting greenhouse gas emissions reductions. However, we recognize that in the broader sense, climate policy also encompasses climate change adaptation and clean growth.

tainty and strong, clear incentives are crucial to avoid locking in systems and infrastructure investments that become stranded in the future or that create further challenges for reaching Canada's climate targets.

### 3.1.2. Policy options

#### **OPTION 1: Strengthen the current output-based approach to electricity sector carbon pricing**

One option for improving the effectiveness of existing federal carbon pricing policy for the electricity sector is to revise the design of the current output-based approach to carbon pricing.<sup>5</sup> Because the federal policy acts as the benchmark for assessing whether provincial and territorial policies are equivalent, this change would ensure that provincial and territorial policies are (or become) equally strong.

The problem with the existing approach is that under the federal OBPS, coal generators receive a higher emissions benchmark than natural gas generators, while clean power generation is excluded altogether. This is at odds with the way OBPS is applied in other sectors, where facilities that produce the same end product (in this case, electricity) face the same benchmark, regardless of which production method they employ. These fuel-specific benchmarks create an uneven playing field for emissions reduction incentives, reducing the effectiveness of the policy.

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5. *Electricity generators in Canada fall under the large emitter carbon pricing scheme known as the output-based pricing system (OBPS; see Dion 2017 for more details on OBPS systems and why they are used). The OBPS can be thought of as a carbon price applied against emissions above a benchmark level of emissions intensity (i.e., tonnes of CO<sub>2</sub> emitted per unit of a given product). In effect, the OBPS is a combination of two policies: a pure carbon tax on all emissions from an industrial facility, and an "output subsidy" that returns carbon tax revenues (in the form of credits) to facilities based on their output, in line with a benchmark level of emissions intensity. These credits can be sold to more emissions-intensive facilities covered by the OBPS as a way of complying with the policy. This arrangement provides facilities with a market incentive to reduce emissions, but one that encourages them to do so by reducing the emissions intensity of production, rather than by reducing output, providing an incentive to reduce emissions by making production cleaner, instead of smaller.*



To resolve this problem, the federal OBPS could instead be applied uniformly to *all generators*, including non-emitting ones. The design could model itself on Alberta's Technology Innovation and Emissions Reduction (TIER) policy, which applied a uniform benchmark of 0.37 tonnes of CO<sub>2</sub> per MWh to all generators and has tightened at a rate of one per cent per year since 2017 (Government of Alberta 2020). This approach would correct the distortions of the existing version and improve incentives to reduce the emissions intensity of electricity generation.

However, this design would also lead to significant interprovincial financial flows. The trading of credits among regulated facilities would lead to windfalls for provinces and territories with large shares of hydroelectricity or other types of non-emitting electricity, while producing significant financial outflows from provinces and territories with large shares of coal or natural gas-fired electricity. Avoiding this outcome is likely part of the reason that federal policy makers adopted the existing approach in the first place.

### **OPTION 2: Eliminate the output-based approach to carbon pricing in the electricity sector**

Another way to align federal policy with net zero goals is to eliminate the output-based benchmark altogether. This would mean no longer providing an OBPS treatment for electricity generation and instead applying a carbon tax to electricity generation that does not return a portion of revenues to producers based on their emissions intensity of production relative to a benchmark. This option would raise the carbon cost for coal-fired and natural gas-fired generators, while leaving renewable producers with no carbon cost instead of the net benefit they would receive under Option 1. The *relative* price differences, however, would remain exactly the same, duplicating Option 1's improved effectiveness relative to the current approach.

Where this option differs from Option 1 is in the implications for consumer costs. Eliminating the benchmark would levy greater total carbon costs on generators, leading to higher relative costs for elec

tricity consumers. This would undermine their incentives to electrify energy end uses—a critical component of any pathway to a net zero economy.<sup>6</sup>

To maintain incentives for electrification under this option, a solution is to return all the revenue collected from generators (which would no longer be going toward an output subsidy under the OBPS) to ratepayers in the form of a consumption subsidy (rebated per kWh).<sup>7</sup> The result would be that while the price of electricity would rise, the ultimate cost to end users would be offset by the consumer rebate. This method of returning the proceeds from electricity sector carbon pricing to ratepayers is already employed in California, where distribution utilities receive the proceeds from carbon allowance auctions and pass them on to their consumers.

Under this kind of policy design, incentives to electrify energy end uses would remain intact because the carbon costs paid by generators would, effectively, not be included in electricity bills. This approach would also avoid creating higher relative carbon costs to consumers on grids that continue to emit because revenues collected in a given province or territory would remain there (as is current practice under the federal carbon levy), making rebates larger in provinces or territories with more emissions-intensive electricity systems. So long as electricity regulators were directed to not consider the effects of the rebate when weighing utility investment decisions from vertically integrated public utilities, there would be no concern about

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6. While this change would also theoretically improve their incentive to avoid consuming carbon-intensive electricity (which would help reduce emissions), in practice, most ratepayers in Canada would not be exposed to these cost differentials across sources of generation, since rates are regulated and typically do not reflect differences in the actual cost of generation at a given time. Ontario is the only partial exception to this, where there is time-of-use pricing, but even this acts as a low-fidelity price signal in the context of electricity's carbon costs, which can change hour to hour or even minute to minute, compared to the simpler off/mid/on-peak distinction drawn in Ontario rates. Rather than providing an incentive for consumers to shift their consumption from high- to low-emitting electricity, the result would simply be that consumers would face higher overall costs and weaker electrification incentives in provinces where grids were higher-emitting.

7. This could pose some administrative challenge in that there would be a lag between calibration of the rate subsidy and the final determination of carbon pricing proceeds from the electricity sector in a given year. However, electricity rate regulators commonly deal with similar challenges when estimating utilities' revenue requirements and setting rates accordingly, and the federal government already faces a similar challenge in calculating its carbon pricing dividends for a province for a given year, so the problem is a tractable one.

the consumer subsidy undermining the overall imperative to reduce emissions, ensuring the policy remained an effective and cost-effective way of reducing sector emissions.

Not only does this policy option offer more effective outcomes than the current approach, it also aligns with a more general case for eliminating an OBPS treatment for electricity. The OBPS is suitable for sectors that are emissions-intensive and trade-exposed, such as steel or cement. The electricity sector, with its low share of trade volumes compared to sectors like cement, does not meet that standard, even if many emissions-intensive and trade-exposed sectors are large consumers of electricity (Dion 2018). The arguments for applying an OBPS approach in the electricity sector largely rest on keeping electricity prices low for ratepayers and potentially for emissions-intensive and trade-exposed sectors that face competitiveness pressures, rather than protecting the competitiveness of the electricity sector itself. But this can also be remedied with the revenue recycling approach described above, leaving little justification for an OBPS approach in the sector.

Because the federal policy would act as the benchmark for assessing whether provincial and territorial policies were equivalent, this change would ensure that provincial policies were (or became) as stringent as the federal one.

### **OPTION 3: Implement a performance standard regulation**

While carbon pricing is an effective tool for reducing emissions cost-effectively in the power sector, it does not provide certainty on future emissions levels—including achievement of Canada's 2035 net zero electricity target. Future emissions levels would instead be determined by how electricity systems and utilities respond to increasing carbon prices (which under the federal policy are set to rise to \$170 per tonne by 2030). Emissions would fall to net zero only if carbon prices were high enough to fully displace all emitting generation. And the *expectations* of utilities and investors are also factors, since investment decisions and future emissions levels are determined by the clarity of the long-term price path and the perceived durability of the overall policy.

A performance standard regulation for the electricity sector can address these challenges. Regarding the challenge of expecta-

tions, the main concern is that utilities and investors might decide to construct new gas-fired generation capacity due to insufficient confidence about future carbon prices. These new assets would be at high risk of ending up stranded as carbon prices rise, creating significant costs for investors, ratepayers, or both, and making the 2035 target harder to reach.

Applying an emissions intensity performance standard to all newly constructed generation facilities in Canada remedies this problem. The standard would be set lower than current best-in-class performance levels for natural gas-fired generation (though there may be a case for not setting it as low as zero, as a way of incentivizing innovation in and deployment of carbon capture and low-emission fuel technologies, such as hydrogen). This would discourage construction of unabated natural gas generation that might otherwise proceed under carbon pricing alone, especially given the uncertainty around the durability of carbon pricing policy. Another complementary option to reduce policy uncertainty would be for the government to hold the policy risk of future policy changes. This could be done, for example, by using the Canada Infrastructure Bank to de-risk big, low-carbon investments, creating a sort of insurance for future carbon incentives (Beugin and Shaffer 2021).

Regarding certainty on the target of electricity production being net zero by 2035, the performance standard could be extended to both new *and* existing facilities by 2035, with the required emissions intensity lowered to zero in that year. To make this policy consistent with net zero, regulated facilities would be able to comply with it by procuring negative emissions, with permissible types and procurement and validation protocols clearly laid out in the regulation. This compliance flexibility would be important for avoiding reliability problems in the event that non-emitting sources of firm generation (or other types of flexibility) are not sufficiently advanced by 2035 to cost-effectively displace the relatively small amount of gas-fired generation that might remain economically viable by then under a high carbon price. It would allow electricity systems to use some fossil generation, sparingly and fully offset, when other options are scarce.

While there are many possible designs for a performance standard regulation, we have focused on the design that would best complement and support carbon pricing in the electricity sector, since the policy is already in an advanced state of implementation. In practice,

implementing this kind of performance standard may simply require extending the coverage and stringency of existing federal performance standards in the sector (Government of Canada 2021a). Provinces or territories that implement similarly stringent policies may be able to secure equivalency agreements with the federal government.

There are other models for how carbon pricing and a performance standard regulation could work, either in tandem or independently, to achieve Canada's goal of a net zero electricity system by 2035 (Jaccard and Griffin 2021). Governments could also implement a flexible performance standard that allows compliance trading among regulated entities. However, when layered on top of carbon pricing, such an approach would add significant complexity to Canada's electricity policy landscape.

#### **OPTION 4: Provide tax incentives or direct subsidies**

While the first three options discussed focus on reducing the emissions intensity of electricity generation or eliminating emitting generation from the sector, one further option is to use tax incentives or direct subsidies to increase the amount of non-emitting generation.

The analogs here are the *investment tax credit* and *production tax credit* instruments used in the United States, whereby wind and solar generation receive either a set percentage of their upfront capital cost back in the form of a tax credit (an investment tax credit), or a credit in dollars per MWh for each MWh of generation from their facility (a production tax credit).

Tax incentives for non-emitting electricity generation are not a new concept in Canada. For example, the accelerated capital cost allowance for clean energy equipment encourages industry to invest in non-emitting generation and energy efficiency equipment by allowing them to expense the purchase of eligible capital expenses on an accelerated basis (NRCan 2022).

While these incentives can help facilitate investment and use of renewable electricity, an initial challenge with investment tax credits is that the credit is not linked to a facility's performance, so more poorly producing facilities earn the same credit as more efficient ones. The production tax credit rectifies this challenge by

linking payments to production. Neither credit, however, creates an incentive to maximize the value of production. In the case of a production tax credit, firms are incentivized by volume, which can often lead to less value. For example, multiple developers may site their facilities in the same strong-wind regime, with their correlated output depressing the prices they can receive in some markets. In addition, governments may face challenges in determining which technologies should be eligible for the tax incentives or subsidies.

While both kinds of credits can support the deployment of renewable electricity, they only *indirectly* drive reductions in the use of emissions-producing sources. Investment tax credits do so by affecting the relative costs of the construction of new facilities, while production tax credits affect the relative cost of generation from facilities that are in operation. Given these shortcomings and the fact that carbon pricing is already in an advanced state of implementation in Canada's electricity sector, investment and production tax credits are more likely to offer a means of *further* bolstering the incentives provided by the carbon price to develop and use renewable electricity. This stands in notable contrast with the United States, where they are often a central plank of federal and state electricity sector climate policy.

Table 2. **Pros and cons of policy options**

	Pros	Cons
<b>OPTION 1:</b> Strengthen the current output-based carbon pricing approach	<ul style="list-style-type: none"> <li>Builds on existing policy architecture.</li> <li>Corrects incentives across available sources of generation. (compared to existing approach)</li> <li>Cost effective (same marginal cost for emissions reductions pursued across the economy).</li> </ul>	<ul style="list-style-type: none"> <li>Federal government target for 2035 would not be reached if cost of marginal emissions reductions to reach net zero emissions exceeds carbon price.</li> <li>Policy uncertainty may constrain or raise costs of emissions reductions and constrain innovation.</li> <li>Trade in compliance obligations among regulated entities would lead to windfalls for provinces and territories with large hydroelectric systems and significant financial outflows from provinces and territories with large shares of coal or natural gas-fired electricity.</li> </ul>
<b>OPTION 2:</b> Eliminate the current output-based carbon pricing approach	<ul style="list-style-type: none"> <li>Same benefits as Option 1.</li> <li>Recycling revenues to consumers (and keeping them in-province) helps avoid carbon cost-driven increases in the unit cost of electricity for consumers, including emissions-intensive and trade-exposed sectors (which would undermine electrification incentives) regardless of the emissions intensity of a given province's or territory's grid.</li> <li>Avoids large financial flows from provinces and territories with large shares of coal or natural gas-fired electricity to provinces and territories with large hydroelectric systems.</li> </ul>	<ul style="list-style-type: none"> <li>Federal government target for 2035 would not be reached if cost of marginal emissions reductions to reach net zero emissions exceeds carbon price.</li> <li>Policy uncertainty may constrain or raise costs of emissions reductions and constrain innovation.</li> </ul>
<b>OPTION 3:</b> Implement performance standard regulations	<ul style="list-style-type: none"> <li>Existing performance standards for coal-fired power provide a potential legal precedent, and perhaps could be extended in their coverage and stringency.</li> <li>Can be calibrated to ensure delivery of a net zero electricity system by 2035.</li> <li>Regulations may have greater perceived policy durability than carbon pricing.</li> <li>Mitigates the risk of utilities and investors constructing new unabated gas-fired facilities that would end up stranded if existing and proposed policies are maintained and carried out.</li> </ul>	<ul style="list-style-type: none"> <li>Overlapping coverage with carbon pricing means that there will be some redundant or duplicative effects (though this can also increase the overall durability of climate policy), achieving similar results but at potentially higher economic cost.</li> <li>Depending on flexibility provisions, could result in high implied carbon costs to deliver net zero in some provinces and territories.</li> </ul>
<b>OPTION 4:</b> Provide tax incentives and direct subsidies	<ul style="list-style-type: none"> <li>Strengthens incentives to build and use renewable capacity.</li> <li>Can have greater perceived policy durability than carbon pricing if given long-term backing.</li> </ul>	<ul style="list-style-type: none"> <li>Has only an indirect effect on incentives to build and use greenhouse gas-emitting capacity.</li> </ul>

### 3.1.3. Preferred solutions

**Preferred solution:** *Strengthen the current federal carbon pricing policy by eliminating output-based pricing in the electricity sector and returning all carbon price revenues from the electricity sector to provincial and territorial ratepayers. Implement performance standard regulations (in addition to a strengthened carbon price) to ensure that the 2035 target for a net zero electricity system will be reached.*

Of the two options we have discussed for revising the current federal approach to carbon pricing in the electricity sector, Option 2 is clearly preferable. While both options can help drive cost-effective emissions reductions and avoid creating disincentives for electrification, only eliminating output-based pricing can do so in a way that avoids large financial flows from provinces and territories with large shares of coal or natural gas-fired electricity to provinces and territories with large hydroelectric systems—flows which are likely to be controversial and unpopular.

A performance standard (Option 3) and strengthened carbon pricing (Option 2) can be complementary. The standard can help address two main shortcomings in carbon pricing: 1) problems created by deficits in its perceived policy certainty and durability; and 2) the inability of carbon pricing to guarantee that the federal target of a net zero electricity system by 2035 will be reached. While the carbon price sends a strong signal to find cost-effective ways to reduce emissions, a performance standard puts a clear limit on allowable emissions from electricity generators. This kind of performance standard could serve as the federal government's promised Clean Energy Standard. It would let market incentives from carbon pricing play a driving role in delivering cost-effective emissions reductions, while at the same time providing a backstop that would ensure delivery on net zero electricity by 2035 (Shaffer and Dion 2022). And by providing a measure of flexibility, it would also ensure that the 2035 target will be met in a way that does not impact electricity system reliability. A more elaborate Clean Energy Standard—for example, one with tradable compliance obligations—would be at best redundant and, at worst, lead to overly complex compliance obligations and higher costs for utilities and consumers. These options could also be enhanced by other means of addressing carbon price policy uncertainty, including the idea mentioned above of using the



Canada Infrastructure Bank to hold the risk of potential future policy changes (Beugin and Shaffer 2021).

Option 4, on the other hand, is complementary to Options 2 and 3, as it further supports the development and use of renewable electricity capacity. This is especially true when incentives and subsidies align with those in other jurisdictions, enhancing opportunities for collaboration and coordination. But it is not strictly necessary to implement this option, as many of its effects can be produced by Options 2 and 3.

A broader point is that while tax incentives and direct subsidies are relatively common in the United States, Canada should be wary of taking climate policy cues from its American neighbour, which uses public spending as the climate policy tool of choice only because of the far greater political difficulty it has encountered in implementing durable, national regulations or carbon pricing.

Table 3. **Compatibility of policy options**

Policy option	Assessment	Interactions with other policy options
<b>OPTION 1:</b> Strengthen the current output-based carbon pricing approach	<b>Unhelpful:</b> The financial flows across provinces and territories that would result would be contentious and likely unpopular.	
<b>OPTION 2:</b> Eliminate the current output-based carbon pricing approach	<b>Very helpful:</b> Corrects for the existing uneven incentives among sources of generation without undermining incentives for electrification or driving large interprovincial financial flows.	<b>Highly complementary:</b> Offers a way of cost-effectively driving emissions down while ensuring they reach their desired level by 2035.
<b>OPTION 3:</b> Implement a performance standard regulation	<b>Very helpful:</b> Can provide certainty where carbon pricing cannot that the target of a non-emitting electricity system by 2035 will be reached.	
<b>OPTION 4:</b> Provide tax incentives and direct subsidies	<b>Optional:</b> Can facilitate greater development and use of renewable electricity.	<b>Complementary with Options 2 and 3:</b> Can further bolster incentives to develop and use renewable electricity.

## 3.2 *Challenge B: Provincial and territorial policies and institutions are not sufficiently coordinated with net zero*

### 3.2.1 The nature of the challenge

Long-term success in decarbonizing electricity systems depends on strong alignment among governments, regulators, and utilities, as international experience has demonstrated (Ferguson 2021). Improving federal climate policy, as we have shown, can provide significant help. But the broader alignment of electricity systems with net zero goals—which means making electricity systems not only cleaner but bigger and smarter in ways that are cost-effective and timely—requires that provincial and territorial policies and institutions (including regulators, public utilities, and system operators) *also* be coordinated with this goal. Given that electricity systems are provincial and territorial domain, the transition might proceed more slowly, be more costly, or even result in missed targets if provincial and territorial governments insufficiently apply their tools and authorities.

The most direct way to address this challenge is to set clear policy at federal, provincial, and territorial levels as it relates to net zero. But there is likely to always be some amount of lag or uncertainty regarding how federal, provincial, and territorial policy implementation connects with longer-term climate goals. Not only would it be difficult for governments to provide full policy certainty all the way to a 2050 emissions reduction target, for example, but it would also likely be unduly rigid. This inconsistency between existing policy and long-term goals creates challenges for key provincial and territorial institutions, particularly electricity regulators. (We discuss the specific role of public utilities and system operators in this transition in Box 4).

Every province and territory in Canada has an electricity regulator (usually a utility commission or an energy board) that provides oversight on system planning, the prudence of investments, and rates billed to users—although the exact scope of each regulator’s mandate often differs from one jurisdiction to the next (Pineau 2021). When a lag occurs between existing policy and long-term climate goals, the existing mandate, rules, and processes under which regulators (as well as other key bodies like systems operators and public

utilities) operate can create significant challenges for the cost-effective and timely attainment of those long-term goals.

The first challenge is that not all provincial and territorial governments have long-term emissions reduction targets, let alone targets that are enshrined in law. In the absence of such targets, regulators lack clear signals about future emissions levels. Clarifying long-term provincial and territorial targets is therefore a first priority in aligning provincial and territorial institutions with national net zero goals.

Another major challenge is that while regulators have very clear and well-established mandates to protect the interest of customers when it comes to reasonable prices and reliable service, the relationship of these mandates to climate change is often unstated, ambiguous, or leaves too much discretion in the hands of regulators. The core objectives in regulators' existing mandates, which were established before greenhouse gas emissions and climate change impacts emerged as major issues, can in some cases get interpreted as being at odds with net-zero-consistent infrastructure investments, as these investments might raise costs to consumers in the interest of delivering benefits that are outside the scope of regulator mandates. Regulators must commonly consider what is in the public interest—which can include the environment and supporting attainment of climate targets; however, without clear direction or explicit policy, they are left with significant ambiguity regarding how emissions reductions should factor into this public interest, how they should be balanced against other goals and priorities, and on what timelines.

A third challenge emerges from the fact that while regulators account for current laws and regulations and are in the business of making long-term investment decisions in the face of uncertainty, they do not have the mandate to make assumptions about what potential future policies could or should look like. This means that even if governments successfully addressed the first two problems—setting out clear targets at both the federal and sub-national levels and clarifying the regulators' role in achieving them—it would not necessarily provide regulators with a sufficient basis to determine whether utility actions and investments are prudently aligned with net zero goals. Such determinations would require regulators to make assumptions about future, unstated government policy, placing them in a de facto policy-setting role that they would be both reluctant and ill-suited to

adopt, since it is elected governments that possess the mandate to make climate policy decisions and to navigate the inherently political choices and trade-offs that these decisions present.

British Columbia's experience, discussed in Box 3 illustrates how these challenges can play out for Canadian electricity systems.

### **BOX 3.**

#### *British Columbia as an illustration of the need to coordinate provincial policies and institutions with climate goals*

In British Columbia, the provincial government has legislated greenhouse gas emission reduction targets of 40 per cent below 2007 levels by 2030, 60 per cent by 2040, and 80 per cent by 2050 (it has updated, but not yet legislated, its 2050 target to net zero), as well as an interim target to reduce emissions 16 per cent by 2025. It has established 2030 emission reduction targets for four sectors: transportation, industry, oil and gas, and buildings and communities (Government of British Columbia 2016). And it also has a CleanBC climate plan and a companion Roadmap to 2030, which was released in October 2021 (Government of British Columbia 2021a and 2021b).

The provincial government has mandated its public utility, BC Hydro, to support the achievement of provincial climate plans and targets. The Government of British Columbia's 2019 mandate letter to BC Hydro directs the organization to ensure its operations align with the government's forthcoming climate plan (CleanBC) (Ministry of Energy, Mines and Petroleum Resources 2019). And a new mandate letter in June 2021 added more specifics, directing BC Hydro to "align (its) operations with targets and strategies for minimizing greenhouse gas emissions and managing climate change risk, including CleanBC target(s)" (Ministry of Energy, Mines and Low Carbon Innovation 2021). In addition, the government has also provided direction to the province's energy regulator, the British Columbia Utilities Commission, to consider government energy objectives, including those laid out in CleanBC.

But despite these positive steps in the form of legislated targets, climate plans and policies, and the mandating of key public institutions, challenges remain around coordination, integration, and implementation. For example, while the CleanBC plan sets out a number of priorities, not all of its components are backed up by legislation and regulations. The plan at times focuses on climate and emissions outcomes without clarity on their implications for the province's energy systems (including the amount and type of energy needed), leaving questions about how

the former will and should translate into the latter. And the plan is also focused on realization of the province's 2030 target, rather than its longer-term targets, leaving questions about how long-term targets will be met.

This insufficient clarity around how the province's emissions targets will be realized makes it difficult for BC Hydro and the British Columbia Utilities Commission to support attainment of the province's climate targets. Uncertainty about the nature and scale of the role of the electricity system in target attainment make it difficult for BC Hydro to plan accordingly, and for the British Columbia Utilities Commission to have a clear basis for reviewing the elements of utilities' submissions that would support attainment of climate targets.

This disconnect is evidenced by the Integrated Resource Plan submitted to the utilities commission by BC Hydro in December of 2021. The Integrated Resource Plan's Base Resource Plan assumes levels of electricity load that would not be consistent with CleanBC or the CleanBC Roadmap to 2030. Instead, the part of the planning document that is consistent with its achievement is found in the Contingency Resource Plan section—which is not the main basis of planning, but rather used to help “prepare for the unexpected”—under an “Accelerated Scenario” which assumes that provincial greenhouse gas reduction targets are met over the milestone years of 2025, 2030, and 2040 (BC Hydro 2021a). This underscores that alignment with climate targets is not part of the main basis of planning at BC Hydro, despite supporting directives from the provincial government. BC Hydro's Electrification Plan (BC Hydro 2021b), which was submitted to the British Columbia Utilities Commission as part of its Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (BC Hydro 2021c), is similarly out of step with the province's climate targets, and was filed prior to the release of the Roadmap to 2030.

Why would BC Hydro submit this kind of IRP? A likely interpretation is that BC Hydro understands that, absent greater policy clarity, the British Columbia Utilities Commission is not necessarily in a position to approve submissions that forecast increases to load that would be in service of the provincial government's stated climate targets, and that BC Hydro has therefore elected to submit an Integrated Resource Plan that it thinks the utilities commission is more able to approve—even though the plan's main planning scenario does not align with the province's climate goals.

The Integrated Resource Plan is currently before the utilities commission, whose review and ultimate decision are still pending, so it is still possible that BC Hydro's final, endorsed plan will better align with climate targets. And even if the current version is endorsed by the British Columbia Utilities Commission, Integrated Resource Plans are planning documents that do not set in stone the direction of

future development of the electricity system, so this plan would not necessarily lock in the trajectory it describes. Still, the fact that such an Integrated Resource Plan would be submitted at all provides evidence of a policy and governance disconnect.

The British Columbia Utilities Commission appears to understand the challenge associated with the context described above, and in June 2021 initiated a staff project to examine the commission's role in British Columbia's energy transition, with the aim of increasing staff, commissioner, and stakeholder understanding of the current energy transition policies and goals in the province and neighbouring jurisdictions (BCUC 2021). It has also invited Fortis BC (the province's main gas utility) and BC Hydro to develop joint load forecasts. But such measures cannot resolve deeper issues of policy uncertainty. They are at best a second-best to government policy that clarifies intentions for the evolution of the province's electricity system in line with climate goals as well as the role that public utilities and regulators will play in delivering it.

Where, due to the factors we describe above, policy gaps or regulators' current mandates lead them to block approval of net-zero-consistent investments, achieving net zero targets will become more costly (including by stranding assets), more difficult, or both. Moreover, these outcomes can as easily result from a *perception* on the part of utilities that regulators will block such investments, leading them to adjust their plans and submissions accordingly. This is especially the case for capital investments with long time horizons, which are common in the sector and in the net zero transition more broadly. And the same can also be true of investments in resilience and adaptation, since such investments can be cost-intensive, and have uncertain rates and timelines of return (Clark and Kanduth 2022). Of course, not every investment will be in the best interest of ratepayers, so regulators denying applications from utilities—even where they are consistent with net zero—is not a problem in itself. Rather, the problem is that cost-effective investments in line with net zero targets (and broader climate objectives) may be blocked simply because the future direction of climate policy lacks clarity or legitimacy from the perspective of the regulator.

Provincial and territorial governments can of course overrule regulator decisions that do not align with net zero, but this is not a desirable model. Applying this tool regularly would be counterproductive. It would undermine the independence of regulatory authorities and fail to make full use of their considerable expertise. Furthermore,

the discretionary nature of these government interventions means that they will not necessarily be consistently or prudently applied as governments change, which risks reducing the speed and efficacy of electricity sector transformations and increasing their costs.

#### **BOX 4.** *The role of public utilities and system operators*

Public utilities are a common feature of Canada's electricity systems. In several provinces and territories, they are large, vertically integrated organizations that manage generation, transmission, and distribution, as well as system planning and operation functions. In others, these functions are delivered separately or by a mix of public and private actors. Ontario and Alberta grant the largest role to unbundled private sector players (Pineau 2021), with not-for-profit independent systems operators given responsibility for the planning and operation of provincial electricity grids and markets.

The prevalence of government-owned public utilities in Canada's electricity systems creates an opportunity for provincial and territorial governments to provide directives instructing them to align their planning and operations with net zero goals. Numerous jurisdictions have already done so, including British Columbia and Quebec, which have tasked their respective public utilities (BC Hydro and Hydro Quebec) to deliver on significant parts of their climate strategies, including increasing electrification. And, in provinces with independent system operators, such directives can also extend to them. Governments could also use performance-based regulations and performance incentive mechanisms—including for electrification, renewable electricity generation, and energy efficiency—to help align utility incentives with net zero goals.

Coordinating net zero goals in this manner is a useful approach, but it faces limits because the decisions and investments made by utilities and system operators are still subject to the scrutiny of regulators (though in some places this scrutiny can be limited for some aspects of system operators' mandates). If regulators' mandates are unclear with respect to net zero goals or if too much ambiguity exists around how climate targets will be achieved, significant risk remains that regulators will not approve the cost-effective, climate-focused investments and decisions that utilities (and system operators) seek to make.

In brief, efforts to align public utilities' and system operators' mandates and operations with net zero goals should be seen as a complement to, but not a substitute for, efforts to do the same for provincial and territorial electricity regulators.

### 3.2.2 Policy options

#### **OPTION 1: Clarify the mandate of provincial and territorial regulators to include alignment with climate goals**

To clarify the core mandate of regulators, provincial and territorial governments could maintain their existing mandate to protect the interests of customers with respect to prices, reliability, and service quality (and therefore maintain their role as an economic regulator), but with clear guidance as to how this relates to climate objectives, including emissions reduction goals and targets, as well as enhancing the resilience of electricity systems to climate change (Clark and Kanduth 2022). In jurisdictions with public utilities and independent system operators, these institutions could also be mandated to pursue climate objectives.

Regulator mandates that include the objective of meeting a jurisdiction's overall emissions reduction targets (and sectoral targets, where they exist) would create an explicit requirement to align decisions and investments with emissions reductions goals and resilience objectives, rather than just with current policy for those goals. This would also clarify that investments that reduce emissions but raise costs for ratepayers should not be interpreted as being at odds with their interests. Maintaining regulators' existing mandate to deliver affordable and reliable power for ratepayers, however, would ensure that they review the merits of emissions-reducing investments with an eye to their cost-effectiveness and potential impacts on reliability and resilience. This would allow them to continue to play the role they are best suited to play—as economic regulators—simply with a new public interest factor to consider. It would also make them active and constructive participants in provincial and territorial net zero transitions.

This option, as we already noted, would be supported by having, at the provincial and territorial levels, clear and legislated emissions reduction targets that align with net zero. While some provinces and territories have announced long-term emissions reduction targets, some enshrining them in law, some provinces and territories have not yet clarified their long-term climate objectives.

A formal directive from a provincial or territorial government—such as a mandate letter or an order-in-council—that clarifies for regulators that they should be pursuing electricity sector development



consistent with stated climate targets would serve as a helpful first step which could be later formalized in legislation.<sup>8</sup>

While this option would maintain the existing role of the economic regulator, it would still put regulators in a de facto policy-making role in the absence of other changes. A policy option that can help bridge the gap between existing policies and the longer-term targets that regulators would now be mandated to pursue is therefore a very helpful complement. Option 3, discussed below, can provide this kind of function.

### **OPTION 2: Broaden the core mandate of regulators to include goals beyond emissions reductions**

An additional option is to expand the core mandate commonly found among Canadian electricity regulators of ensuring affordable, reliable power for consumers. In particular, mandates could be formally extended to include explicit requirements to consider broader societal objectives such as equity, justice, and income equality. Whatever form this takes, it would shift regulators away from their traditional role as economic regulators weighing goals specific to the electricity system such as reliability and affordability (and emissions reductions) to a broader position that requires defining, shaping, and balancing larger societal considerations and priorities. This would effectively shift some amount of policy decision making to independent adjudicative bodies and away from elected officials and government bureaucracies.

### **OPTION 3: Guide the work of regulators, public utilities, and other market players with energy plans and pathway assessments**

While it is critical that the gap between enacted climate policies and a jurisdiction's longer-term climate goals be closed as completely and expediently as possible, some amount of inconsistency is likely to persist, as we discuss above. Recognizing this, governments could use energy plans and pathway assessments to provide guidance for regulators and other decision makers on how policy gaps might be closed in time and what a cost-effective system transformation in line with the

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8. Including climate resilience in this mandate would also be very helpful. However, operationalizing a resilience mandate would require better data, standardized resilience metrics, and improved climate risk assessment and disclosure to enable governments, regulators, utilities, and system planners to make informed decisions in the face of a changing climate (Clark and Kanduth 2022).

jurisdiction's climate goals might look like. Such guidance documents, while non-binding, would give regulators and other decision makers such as system operators, public utilities, and private market players a reference against which to weigh decisions that have implications beyond the present policy horizon. They would serve as temporary substitutes for more concrete policies to follow, giving regulators a credible basis for their decisions and eliminating the need to make assumptions about future government policy or take on de facto policy-making roles.

This option relies on two critical guidance documents: a comprehensive energy plan and a periodic assessment of available pathways for electricity supply.

A comprehensive energy plan for developing a net zero energy system is a document produced by the provincial or territorial government to support decision making from regulators and other market actors. It should provide clarity on things like targets for the uptake of electrified energy end use technologies (including heat pumps and electric vehicles); intentions for driving increased uptake of different types of non-emitting energy; the role envisioned for energy efficiency measures and building retrofits; the intended role for the gas network, especially over the long term; and the way all these changes would affect total demand for different types of energy—including electricity—in the province or territory. Clarity about future load profiles, in particular, is critical to rapidly achieving the “bigger” component of electricity systems that net zero requires, especially given that regulators are likely to be concerned about overbuilding the system.

To effectively guide regulator decision making, this energy plan should provide as many quantitative specifics as possible while also acknowledging uncertainties by using ranges, sensitivity analyses, or multiple scenarios. Vague or directional estimates and targets (rather than concrete and specific ones) are insufficient for guiding regulator decision making.

Comprehensive energy plans should include objectives and outcomes; metrics to measure progress; action plans with implementation timelines; and proposed governance structures that outline the roles and responsibilities of various provincial and territorial institutions. They should not be overly prescriptive, leaving space for utilities and system planners to execute the plans in ways that keep costs

low, maintain reliability, and enhance resilience. And they should be developed with broad stakeholder and public consultation, including the substantial involvement of Indigenous Peoples (ICE 2022).

These plans could guide actions and investment decisions in every province and territory, regardless of market structure. In vertically integrated markets, the plan would be implemented through Integrated Resource Plans—roadmaps for how utilities plan to meet future needs and objectives— and incentive structures designed by regulators. In the unbundled electricity sectors of Alberta and Ontario, a comprehensive domestic energy strategy would shape private investment decisions as well as the system plans, market and rate structures, and procurement processes designed by independent system operators and regulators.

Lastly, to operationalize this approach, provincial and territorial governments would need to create a mandate or issue a directive for the regulator or system operator to implement the comprehensive energy plans. For example, in Ontario, the Minister of Energy issued a directive to the Independent Electricity System Operator to submit an implementation plan showing how it would achieve goals and objectives outlined in the province's 2017 Long-Term Energy Plan (IESO 2017).

A second complementary document to deliver this option is a periodic assessment of available pathways for electricity supply. To enhance credibility and independence, this document should be developed by arms-length government agencies, academic researchers, or trusted research institutes, rather than by the government itself. And it should be based on rigorous independent analysis of the resource scenarios and system development pathway options available to the province or territory—the varying mixes of generation technologies and flexibility sources such as storage, demand-side management, and electricity trade with other provinces and territories that the province or territory could adopt as it pursues alignment of its electricity system with net zero, as well as the relative certainty, costs, and benefits of these pathways. This assessment would serve as a valuable resource to regulators weighing the affordability and reliability of utility submissions that have implications for alignment with longer-term climate goals. And because it would be periodically updated, they could be assured that it reflects the current (or at least recent) state of different technological options and their relative costs.

**OPTION 4: Require an internal carbon price for regulator decision-making**

Provincial and territorial governments could require that regulators apply an internal price on carbon as part of their analysis of submissions. This would consist of a theoretical or assumed cost per ton of carbon emissions that is then factored into analytical and decision-making processes. Many companies in Canada, including some electric utilities, already apply an internal carbon price to guide long-term planning (Sustainable Prosperity 2013).

Canada already has a price on carbon that is set to rise to \$170/tonne by 2030, but the price path beyond this point has not yet been established. Applying an internal price on carbon could help address this gap by stipulating what levels of carbon price should be considered when regulators are reviewing investment decisions that have implications for emissions levels or reductions beyond the 2030 horizon. This requirement could potentially extend as well to planning and investment decisions being made by public utilities themselves, and/or governments could require that all utilities, public and private, include such assessments in their submissions to regulators.

Such a price on carbon would allow regulators to explicitly weigh the value of emissions reductions in their assessments of an investment's cost-effectiveness for ratepayers. It could also be set at different levels than the federal price trajectory. For example, it could be calibrated to a Social Cost of Carbon that estimates what the actual marginal costs of emissions are (though such a figure would need to be credibly estimated and calibrated to serve as an effective decision support tool). Or it could adopt a higher price sooner than the federal one, recognizing that long-lived investment decisions should be made with an eye to where carbon prices are going, not only where they are today and where they will (or might) go in time. Or it could represent the estimated implicit carbon price required to achieve net zero in a given province or territory (Kaufman et al. 2020).

Table 4. Pros and cons of policy options

	Assessment	Interactions with other policy options
<b>OPTION 1:</b> Clarify the mandate of regulators to include alignment with climate goals	<ul style="list-style-type: none"> <li>Allows utility commissions and energy boards to maintain their existing role as economic regulators focused on ensuring affordable and reliable power for consumers, and makes them constructive participants in the net zero transition.</li> <li>Eventual backup in legislation defining a regulator's mandate would solidify government directives regarding the fact that investments that raised costs in the interest of reducing emissions should not be considered at odds with the interests of ratepayers.</li> </ul>	<ul style="list-style-type: none"> <li>Incomplete on its own since, even with a clarified mandate, so long as gaps persist between long-term climate targets and policy implementation, regulators will be constrained in their ability to judge the merits of submissions that have implications for long-term climate targets.</li> <li>If regulators were to make assumptions about future policy, they would effectively be setting climate policy themselves (a role more appropriate for legislatures and governments).</li> </ul>
<b>OPTION 2:</b> Broaden the core mandate of regulators to include other societal goals	<ul style="list-style-type: none"> <li>Ensures that goals like affordability and reliability get weighted alongside other imperatives, including ensuring equity.</li> </ul>	<ul style="list-style-type: none"> <li>Expanding regulators' mandate to include broader societal goals effectively asks regulators to decide how these goals should be balanced, which strays far outside their traditional role as an economic regulator.</li> <li>Where their decisions are made based on their subjective interpretation of how the various goals should be balanced, these decisions are open to litigation, which can slow down (and even overturn) implementation of regulator decisions.</li> </ul>
<b>OPTION 3:</b> Guide the work of regulators and other actors with energy plans and pathway assessments	<ul style="list-style-type: none"> <li>Provides a clearer basis for regulator decisions in cases where long-term climate targets are implicated but there is not yet concrete climate policy to fully achieve them.</li> <li>By providing vital missing information to regulators, energy plans and pathway assessments would allow them to maintain their existing role as an economic regulator providing consumer-minded checks and balances to the specific development plans and investments envisioned by governments and utilities.</li> </ul>	<ul style="list-style-type: none"> <li>Energy plans and pathway assessments may still leave too much ambiguity in some areas, particularly if they remain too high-level or directional and fail to provide credible quantitative estimates. On the other hand, if they are too prescriptive, they risk undermining regulator decision-making processes.</li> </ul>
<b>OPTION 4:</b> Require that an internal carbon price be used in regulator decision-making	<ul style="list-style-type: none"> <li>An internal carbon price provides a clear and rigorous basis for weighing the value of emissions reductions against other costs and considerations.</li> </ul>	<ul style="list-style-type: none"> <li>There are many possible figures that regulators could use, and even with clear and stable guidance from governments, there is a risk of poorly calibrated figures swaying regulator decisions.</li> <li>If the internal cost of carbon is only applied in decisions related to the use, replacement, or phase-out of emitting generation sources, it may be of limited help in supporting regulator decisions surrounding electrification options (where emissions reduction benefits would stem not from avoided emissions in electricity generation but from reduced use of liquid or gaseous fossil fuels in transport, buildings, or industry).</li> <li>In addition to methodological challenges, internal carbon prices present difficult questions around who should be granted authority to set the internal carbon price.</li> </ul>

### 3.2.3 Preferred solutions

**Preferred solution:** *Extend the mandate of regulators to include delivery of emissions reduction goals and resilience objectives and guide their work (and that of other market actors) with energy plans and pathway assessments.*

Arriving at an optimal solution to this challenge requires combining multiple policy options. In particular, Options 1 and 3 are both very helpful and highly complementary. By providing direction to clarify how regulator mandates connect with climate goals, Option 1 can help avoid the misconception that taking climate action is at odds with the goal of providing affordable and reliable power to consumers. And, where they exist, providing similar direction to public utilities and system operators can be a helpful extension. Bridging policy gaps with energy plans and pathway assessments (Option 3) is highly complementary to Option 1. While these documents are non-binding and subject to change, they enable regulators (and other actors) to make better-informed, more defensible decisions.

Further changes might be required in some jurisdictions to execute these two options. For example, in some jurisdictions, the existing duties of regulators might need to be expanded. Not all regulators, for example, are responsible for reviewing system plans and load forecasts. While many regulators review Integrated Resource Plans from public utilities, plans from system operators in some jurisdictions such as Ontario do not receive regulator scrutiny. In addition, governments might need to issue directives for regulators or system operators to support the implementation of comprehensive energy plans.

Where necessary, extending regulator mandates to cover a wider range of utility and system operator activities would better leverage the broad expertise of regulators and the benefits of adjudicative process, by ensuring that systems were being aligned with net zero in ways that made sense for ratepayers. This expanded oversight could extend beyond the review of specific investments and rate cases to include system plans and load forecasts, planned capital investments, proposed market designs, and public utility and government procurement processes.

Provincial and territorial governments would also need to ensure that regulators receive the resources, capacity, and authority required

to fulfill their updated mandates. This can include not only human and financial resources, but also the mandate to invest in new infrastructure, technology, or broader innovation that may be otherwise perceived by regulators as unduly risky or costly, for example through an “innovation sandbox” approach (Carlson and Nciri 2021).

An internal price on carbon can be a complement to these two priority measures, providing an additional means of considering the cost-effectiveness of investments intended to align electricity systems with net zero. But given the difficulties associated with establishing a reliable and credible figure—especially when the calculation involves a social cost of carbon or estimating the implicit carbon price for meeting climate targets—internal prices on carbon should not determine regulator decisions. Instead, internal carbon prices should serve as an additional screen that decisions can be subject to or an additional type of evidence to weigh. Given the challenges associated with executing internal carbon prices, they should be seen as an optional measure rather than a necessary one. And to work as an effective decision support tool, an internal price on carbon should be independent and credibly set, and its application should extend to emissions reductions outside of the electricity system itself (for example, by fuel switching from gasoline to electricity in the transport sector).

Critically, a fundamental expansion of regulator mandates beyond the traditional role of economic regulator as proposed under Option 2 would be unhelpful. Regulators already consider impacts on other societal goals when regulating in the public interest, which includes ensuring equitable access to electricity. But decisions that more fundamentally determine how larger societal goals should be balanced are best left to legislatures and governments, since they are in the best position to weigh such competing priorities. Asking regulators to undertake this work not only leaves their decisions vulnerable to litigation, but it also risks attempting to depoliticize decisions that are inherently political, to the detriment of electricity system governance and even democratic decision making writ large.

Governments should continue to be responsible for pursuing broader social objectives like equity, reconciliation, Indigenous self-determination, and economic equality. However, regulators may be implicated in the realization of these goals, as government decisions and policy in these areas will affect economic regulators’ decisions and process. Governments can ensure that provincial and territorial regulators are equipped to factor in these kinds of considerations

when regulating in the public interest. For example, governments could proactively include equity-seeking groups and rights holders—particularly Indigenous peoples—in regulatory governance structures and decision-making processes (ICE 2022); they could set performance indicators on community participation in renewable energy development; and they could establish equity targets with respect to communities served by strategic electrification efforts.

Finally, the success of the preferred policy options we have discussed is greatly supported by provincial and territorial governments establishing long-term emissions reduction targets, ideally in legislation. Long-term targets are a necessary foundation for mandates that are updated to include realization of climate goals. Without them, regulators will lack clarity about the ultimate aim of provincial and territorial climate policies, whether existing or planned.

Table 5. **Compatibility of policy options**

	Assessment	Interactions with other policy options
<b>OPTION 1:</b> Clarify the mandate of regulators to include alignment with climate goals	<b>Very helpful:</b> Existing ambiguity around how regulator mandates relate to climate goals needs to be clarified.	
<b>OPTION 2:</b> Broaden the core mandate of regulators to include other societal goals	<b>Unhelpful:</b> Diverging from the core function of economic regulator is not a practical solution, and balancing of societal goals is best left to elected governments.	
<b>OPTION 3:</b> Guide the work of regulators with government energy plans and pathway assessments	<b>Very helpful:</b> Credible signaling of how climate goals will be met is important given that gaps between implemented policy and long-term ambition are likely to persist.	<b>Complementary to Option 1:</b> Directives and legislation can ensure that regulators and other key public institutions set their sights on the right target while energy plans and pathway assessments and strategies provide what they need to make informed and defensible decisions.
<b>OPTION 4:</b> Require that an internal carbon price be used in regulator decision making	<b>Optional:</b> An internal carbon price can help focus and ground regulator decisions, but risks providing biased or insufficient direction on its own.	<b>Complementary to Options 1 and 3:</b> An internal price on carbon can serve as another way of guiding regulator decisions. But given the difficulty in calibrating reliable cost figures, it should not serve as the sole basis for guiding regulator decisions.



### **3.3** *Challenge C: Creating resilient electricity systems aligned with net zero could put upward pressure on electricity rates*

#### 3.3.1 The nature of the challenge

Improving climate policy and institutional coordination to address the challenges we have discussed in Sections 3.1 and 3.2 can help ensure that planning processes and decision-making are set up to support a cost-effective transition. Still, even with better policy and governance, the potential for upward pressure on electricity rates represents a significant challenge.

Power systems across Canada face significant maintenance and infrastructure investment requirements, independent of the need to align them with net zero. Transforming these electricity systems to meet net zero goals will require additional capital investments in generation facilities, transmission and distribution infrastructure, storage, and more. And the need to make existing and new infrastructure climate resilient will require still further investment. (For more information, see our companion report *Bigger, Cleaner, Smarter: Pathways for aligning Canadian electricity systems with net zero*.)

Recent global studies have found that system investments will indeed raise rates for consumers. One study estimates that they could raise electricity prices 20 per cent by 2050 (Krishnan et al. 2022). These kinds of rate pressures have also begun to emerge in Canada. For example, Nova Scotia Power announced earlier this year that it was filing a submission to increase its rates, attributing the change to recent and planned investments to reduce emissions from its electricity production and build a more climate-resilient electricity system (Withers 2022).

Despite this, the possibility remains that, in some jurisdictions, investments to align electricity systems with net zero will lead to lower overall costs of electricity. Investment costs may rise, but the variable costs of production could fall enough to offset them (because of the near-zero operating cost of renewables), delivering net savings for households.

But even where this proves to be the case, many of these investments will come with upfront costs that could put upward pressure on rates in the interim, especially where systems become larger and more flexible in anticipation of greater demand from the electrification of energy end uses that is only starting to come online. While investment cost amortization on electricity bills can help to smooth out these up-front costs, they may nevertheless result in increased rates.

At the same time, however, electricity costs are only one part of what households pay for energy and energy services—a category that currently includes significant expenditures on fossil fuels for heating and transportation. Our 2021 report *Canada's Net Zero Future* found that, on average, households in all provinces and territories and across all income groups will spend less on energy services as a share of their incomes under a transition to net zero than they do now (Dion et al. 2021). This means that even if electricity prices increase, falling expenditures on fossil fuels and on more efficient electrified technologies can be expected to more than offset the average increases in electricity costs, even as electricity use rises.

Figure 3 presents new analysis by Dolter, Winter, and Guertin (2022), commissioned by the Canadian Climate Institute, that estimates the potential rate pressures that some provinces could experience as they align their electricity systems with net zero and make investments in their climate resilience. It also illustrates the larger context of falling overall costs of energy services as a share of income.

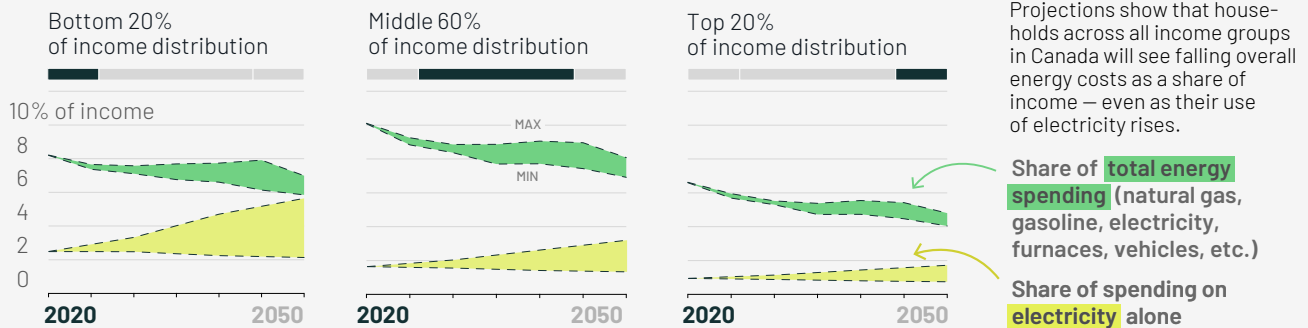
Even with overall expenditure on energy services as a share of income expected to fall, the potential for investments in electricity system to increase rates raises a number of concerns. Among them:

- Higher rates could make electricity less affordable for households and undermine business competitiveness.
- Higher rates may have a greater impact on lower-income end users, which has implications for equity and for energy poverty.
- Outcomes may be uneven from region to region, with residents in provinces and territories where decarbonization will require more significant investment (particularly those that currently rely on fossil generation) potentially experiencing disproportionate rate increases.

Figure 3.

# Canadians will spend less of their income on energy, but without a new approach, electricity rates could still go up

## Energy will become cheaper for Canadians overall...

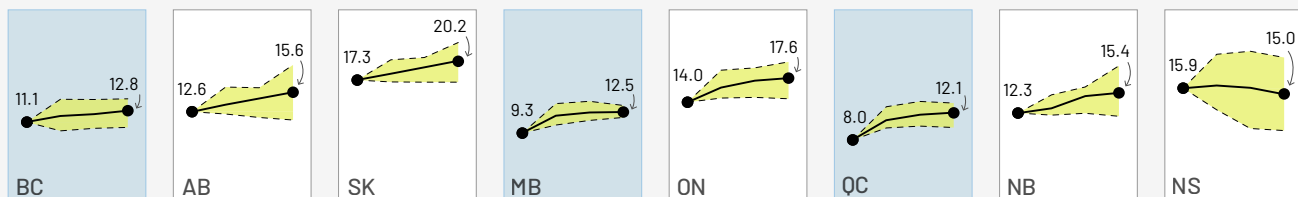


Projections show that households across all income groups in Canada will see falling overall energy costs as a share of income – even as their use of electricity rises.

## ...but the impact on the price of electricity may vary from province to province.

Currently relies on:

- hydroelectric generation
- thermal electricity generation (coal, natural gas, or nuclear)



Electricity rates might modestly increase—or even decline—given the decreasing costs of renewables and storage. But in some regions, in some scenarios, rates could increase more significantly as Canada modernizes its electricity systems. Smart policy can mitigate these potential rate increases and help keep electricity affordable for Canadians.

Sources: Dion et al. (2021); Dolter, Winter, and Guertin (2022).



- Higher electricity costs could undermine the business case for end-use electrification, making attainment of emissions reduction goals more difficult and costly (Davis 2021).
- Rising electricity rates could undermine political support for a broader net zero transition, which could also make climate policy implementation and attainment of goals more difficult. Ontario’s decision to cancel its feed-in tariff program, for example, was made in part due to concerns over rising costs of electricity (IESO 2018). Moreover, a risk of potential cost increases—or even just the perception of such a risk—can be as damaging to public support for climate action as can actual cost increases.

For all these reasons, mitigating potential upward pressure on rates will be a critical challenge as Canada aligns its electricity systems with net zero.

### 3.3.2. Policy options

In this section we discuss several high-level policy options for alleviating potential upward pressure on electricity rates and supporting equity across income groups. These options offer different ways of shifting how investment costs are borne, both within and outside the ratepayer base.

Within the ratepayer base—the individuals or entities that pay electricity bills in a given jurisdiction—utilities could change how costs are allocated within and across consumer classes to alleviate pressures on certain groups (see Options 1 and 2). Or governments could step in to fund a portion of investment costs—effectively extending payment for investment costs to the broader tax base (see Options 3 and 4).

#### **OPTION 1: Shift the way investment costs are borne across ratepayer classes**

Under this option, regulators and governments (via directives to regulators) could pursue new approaches to allocating investment costs across ratepayer classes—industrial, commercial, and residential consumers. Some amount of inter-class cross subsidization already exists in many provinces and territories, where commercial users partly subsidize lower rates for residential consumers (though

not typically exceeding 5 per cent of each ratepayer class's share of total costs). Industrial users more commonly pay a rate close to their actual share. Further cross-subsidization could be used to lower rates for all residential consumers, or just for low-income ones (see Option 2).

**OPTION 2: Re-allocate costs among residential ratepayers to reduce costs for low-income households**

Under this option, higher income parts of the residential ratepayer class would cross-subsidize lower income ones—known as intra-class cross subsidization. This would help address the fact that electricity costs tend to be regressive—that is, the costs are disproportionately borne by lower-income households as a share of their income (Baker et al. 2021). Low-income supports of various types exist to address this regressivity, but these programs and supports may be inadequate to address disproportionate pressures on low-income households as investment costs rise (see Box 5). Providing increased support to low-income households via cross-subsidization would not only reduce their costs and alleviate energy poverty, it would also better enable and encourage their switch from fossil fuels to electricity (though programming to help them with the costs of associated capital investments is likely a necessary complement).

**BOX 5.** *Current supports and rebates for low-income households in Canada*

In 2016, 21 per cent of Canadian households experienced energy poverty—defined as spending more than 6 per cent of income on energy needs (CUSP 2019). These numbers are significantly higher for some groups, notably rural households, of which 29.3 per cent experience energy poverty. While supports and rebates can alleviate economic pressures for households at risk of energy poverty, several studies have shown that current programs are insufficient (Shaffer and Winter 2020; Ecotrust Canada 2020). In particular, the effectiveness of these programs depends on their design, eligibility requirements, application process, and administration and financing for the program.

In Canada, there are different types of support and rebate programs offered, each with their own advantages and disadvantages. A first type of support is one-time protection programs, which generally offer annual lump sum payments towards

energy bills. These kinds of programs are most effective at supporting households that display immediate need for assistance. However, they are not sufficient in assisting with ongoing energy needs and do not allow households to divide the lump sum payment from month to month.

Ongoing protections are those that address the need for ongoing assistance. They can be applied as credits on bills or rate subsidies. Credits on bills help lower the monthly cost of energy for households by applying a fixed or variable credit. Fixed credits are normally determined based on household income and size, whereas variable credits, which also consider household income and size, differ depending on household energy usage. Variable credits are generally more effective as they consider household energy intensity to apply a rate subsidy that better addresses a household's needs. Rate subsidies are used to modify the way qualifying households are charged for electricity by explicitly lowering the price they pay.

Tax credits for energy needs are another option, though they are not a common approach. Ontario, however, offers tax credits to households with low- to moderate income and offers a separate tax credit for Northern communities. One advantage to using tax credits is that it streamlines the qualification process for energy assistance by going through the tax system. However, tax credits do not directly and immediately address energy poverty as there is typically a time lag for compensation.

Under the types of support programs discussed here, most eligibility requirements consider household income, but income is not the only indicator of energy poverty. Other identity factors may leave certain households more vulnerable to energy poverty, including, age, family size, medical needs, disability, and region (for example, households in remote locations, including Indigenous communities, may face barriers to accessing outreach programs). These are important considerations for policymakers to take into account when designing support programs for households at risk to energy poverty.

Determining eligibility based on multidimensional indicators of energy poverty is important to effectively target vulnerable households but can be administratively complex and costly. For example, some programs, such as the New Brunswick Emergency Fuel Benefit, determine eligibility on a case-by-case basis. While case-by-case eligibility requirements represent a more equitable and accessible approach for households facing energy poverty, they can make it very difficult to streamline administrative processes.

Another issue affecting the value of support and rebate programs is the intake processes. Some government agencies enroll households automatically through

various forms of social service programs. This is helpful because governmental agencies can track a household's status and data and streamline participation for households in need. However, many programs are managed by utilities and currently do not have systems to streamline the application process. This increases cost for application processing and reduces the number of applicants, as many eligible participants may not be aware of the programs.

Furthermore, some program applications are offered primarily online, which can create barriers to access for households with limited or no internet access, especially low-income households and remote communities.

Overall, given these and other challenges, existing assistance and rebate programs in Canada are straining to meet objectives of equity and affordability. In addition, the current challenges and limitations of these systems will be exacerbated by increasing system investment costs and associated rate pressures (Shaffer and Winter 2020; Ecotrust Canada 2020).

### **OPTION 3: Governments fund a portion of electricity system investment costs via the tax system**

This option would see governments absorbing some of the costs of electricity system investments, rather than recovering the investment costs from ratepayers alone. Governments could use value-added taxes, corporate or personal income taxes, debt, or a portion of carbon pricing revenues to provide funding. Each of these has pros and cons in terms of their effects on cost incidence and overall economic efficiency (Dahlby 2008), and all of them would help defray the costs that are borne by ratepayers. But as with the other policy options we have discussed, this approach would not reduce total costs but only change who pays, and how. Ratepayers would still experience the costs of electricity system investments, but in different ways and to differing degrees (see Dolter and Winter forthcoming). Still, bearing costs in these different ways could have significant effects on consumers' incentives for electrification, on equity, and on political support for energy transitions.

This kind of public funding measure is not new. Provincial, territorial, and federal governments already have programs that fund infrastructure investments. For example, Infrastructure Canada's Investing in Canada Plan funds a range of infrastructure needs through bilateral agreements with provinces and territories, including for public transit,

roads, and broadband connectivity (Government of Canada 2021b). Governments also routinely invest in transport infrastructure (including transit, roads, and highways) without an expectation that the full costs should be recovered solely from users.

The case for doing the same for electricity system investments is supported by the fact that the goal of reaching net zero changes the context in which these investments are being made. Historically, the main beneficiaries of electricity systems were their users, so it made sense to recover all of the associated costs from the ratepayer base. But in the net zero transition, electricity systems are being used to deliver benefits not just to users but to society as a whole in the form of emissions reductions, making a case for the general population to bear a portion of their costs. And owing to unique features of electricity markets and regulations, investing public funds in electricity systems would not lead to problematic distortions or perverse incentives in the ways they might in other sectors. (We discuss this further in Box 6).

**BOX 6.***Subsidizing investment costs in electricity systems causes minimal distortions to incentives*

While energy subsidies can lead to market distortions, and as a result over production and consumption, providing support against electricity system investment costs creates minimal distortion of producer and consumer incentives.

When it comes to the incentive effects of subsidizing investment costs, the electricity sector is somewhat unique in that the way it is already regulated mutes the response that would be expected from producers in a sector that was more driven by market dynamics. In normal circumstances, subsidizing investment costs would create concerns that systems would get overbuilt. But every province and territory has an existing economic regulator in place in the electricity sector whose job is to ensure that the financial incentive that utilities have to build more infrastructure (in order to earn a return under their regulated cost-of-service-recovery compensation model) does not result in ratepayers paying for a system that is overbuilt (and thereby of greater cost) compared to their needs. Indeed, it is the very fact that economic regulators are already in place as a check on these types of monopoly power excesses that allows governments to have confidence that providing supports against electricity system investment costs can be an economically efficient means of providing support for provincial and territorial electricity



transitions—especially if some of the other challenges we discuss in this report (particularly challenge 2) are successfully addressed through policy.

In terms of consumer incentives, public investment can create scope for a rebound effect, where usage of an energy source rises simply by virtue of its overall costs falling. But such an effect would be at least partially desirable, since greater overall use of electricity is consistent with the more electrified energy end-use future that is needed to meet net zero targets. To the extent that the rebound effect drives wasteful and inefficient use, this could be remedied through improved rate design. Better rate designs will be essential to improving the current, often weak, incentives that consumers face to use electricity in ways that reflect actual system costs.

The scope to improve rate design so that ratepayers face better incentives might in fact grow as a result of providing supports against investment costs. Defraying investment costs in electricity systems would create opportunities to devise new rate structures that create improved incentives for use that is cost-effective from a system perspective. Indeed, regulators could create structures that allow some ratepayers' total bills to drop significantly if they were willing to, for example, shift their consumption away from when system costs were high or adopt load control technologies—known solutions that consumers have not welcomed with open arms to date, but that may become more saleable in a context where rate pressures are being mitigated and stand to be mitigated even more where users are willing to consume electricity more flexibly.

Governments could target their support in a variety of ways. For example, they could fund research, development, and demonstration projects; provide tax credits; co-fund large projects or infrastructure; or simply provide supports directly to ratepayers. Each option has its own pros, cons, and design considerations. For the purposes of this discussion, the point is that such supports materially mitigate potential rate pressures.

#### **OPTION 4: Governments provide targeted supports for low-income households**

Under this option, governments would provide direct support to low-income households instead of funding investment costs directly (as in Option 3). This differs from Option 2 in that the supports would be funded out of the tax base. These supports could be provided through a range of means, including via utilities, income tax returns, or as an extension of carbon pricing dividend distribution schemes.

Table 6. Pros and cons of policy options

	Pros	Cons
<b>OPTION 1:</b> Shift the way investment costs are borne across ratepayer classes	<ul style="list-style-type: none"> <li>There are precedents for this approach—many provinces and territories already reallocate costs across consumer classes.</li> </ul>	<ul style="list-style-type: none"> <li>Political opposition: the potential exists for pushback from other ratepayer classes if their rates increase significantly.</li> <li>Higher rates in other classes may undermine support for electricity sector transformation and decarbonization more broadly (e.g., from key industrial sectors).</li> <li>Moving costs within the ratepayer base may be insufficient to address pressures and does not tackle inequalities within classes.</li> <li>Subsidization of residential consumers by commercial or industrial consumers could lead to higher indirect costs for households if those costs are passed down.</li> </ul>
<b>OPTION 2:</b> Re-allocate costs among residential ratepayers to reduce costs for low-income households	<ul style="list-style-type: none"> <li>There are precedents for this approach—some cost re-allocation is already done to fund utility-run low-income rebates.</li> <li>Addresses economic inequality and promotes equity by redistributing costs from lower-income households to higher-income ones with more ability to pay.</li> </ul>	<ul style="list-style-type: none"> <li>Political opposition: the potential exists for pushback from higher-income households if their rates see notable increases.</li> <li>Potential implementation challenges with this approach (e.g., defining income categories, determining what shares to reallocate) that utilities and regulators may not be well-positioned to navigate.</li> </ul>
<b>OPTION 3:</b> Governments fund a portion of system investment costs via the tax system	<ul style="list-style-type: none"> <li>Supports equity by ensuring that the costs of addressing climate change by aligning electricity systems with net zero are borne by the beneficiaries (i.e., society as a whole) rather than just ratepayers alone.</li> </ul>	<ul style="list-style-type: none"> <li>Political opposition: some taxpayers will question why they should pay for electricity infrastructure (as opposed to just ratepayers paying for it).</li> <li>Absent the policy interventions we describe for addressing Challenge 2 (see Section 3.3), projects receiving public investments might not be subject to the kind of scrutiny and oversight from regulators that can help ensure their necessity and cost-effectiveness.</li> </ul>
<b>OPTION 4:</b> Governments provide targeted supports for low-income households	<ul style="list-style-type: none"> <li>Utilities and regulators do not necessarily have clear insights on income-related pressures. It can be more practical for rebates to be designed and administered by governments, which possess better information on these topics.</li> <li>Instead of requiring one class of ratepayer to subsidize another in order to improve equity (see Option 2), this approach obliges society as a whole to bear the costs. A broader base makes improving price equity less burdensome on other ratepayers and fairer overall.</li> </ul>	<ul style="list-style-type: none"> <li>Political opposition: some taxpayers may question why they should subsidize low-income electricity bills (as opposed to just having ratepayers pay for it).</li> <li>Potential implementation challenges with this approach (e.g., governments aren't often equipped to link tax data to electricity use).</li> </ul>

### 3.3.3. Preferred solutions

**Preferred solution:**

*Governments fund a portion of investment costs and provide supports for low-income households from the tax base.*

Reallocating costs within the residential ratepayer class (Option 2) can help by shifting the cost burden from low-income households to higher-income ones with more ability to pay. And shifting it across ratepayer classes (Option 1) could in theory help with equity concerns by alleviating pressures on residential ratepayers. But because both options simply move costs around within an existing ratepayer base, they fail to fundamentally address the potential rate pressures we have discussed. They would likely also face significant pushback from the parts of the base whose costs would rise. In addition, subsidizing residential rates by increasing commercial or industrial rates might not reduce cost pressures on households, since commercial and industrial ratepayers may simply pass on their costs to residential consumers. For these reasons, Option 1 would be unhelpful, and Option 2 remains optional at best.

There is a clear rationale for instead funding overall investment costs and low-income supports out of the tax base, as we describe in Options 3 and 4. The status quo approach—in which the costs are only distributed across ratepayers—makes much less sense in the context of an electricity system transformation to align with net zero goals.

The rationale for adopting a new approach is three-fold. First, bearing the costs of electricity investments more broadly makes sense because the benefits of these investments are widely distributed. Recovering costs from ratepayers alone might have made sense when they were the sole beneficiaries of the investments, but now that system investments yield broader societal benefits, there is a case for sharing their costs more widely as well.

Second, electricity systems are a vital type of infrastructure. Electricity is an energy system that is already in near-universal use and will only become more vital to a modern 21st-century economy. Moreover, such systems represent “safe bets” that will be essential for meeting decarbonization and net zero goals under all possible scenarios (Dion et al. 2021). Provinces and territories can justify making direct investments in this type of infrastructure in the same way they do others such as transit and roads.

Third, funding a portion of electricity system investments out of government tax bases instead of the ratepayer base can offer a fairer way of sharing their costs. While each federal, provincial, and territorial tax system is unique in terms of how progressive or regressive it is, they all tend to be more progressive than ratepayer cost recovery, which can lead to costs landing disproportionately on low-income households.

Options 3 and 4 can better address potential upward pressure on electricity rates than the alternatives we have discussed. These options are not without cost for ratepayers, however, since they still cover those costs through their taxes. But the costs are borne differently, in ways that smooth out the investment across a wider population. These solutions can offer a considerable benefit to ratepayers, particularly in

Table 7. **Compatibility of policy options**

Policy options	Assessment	Interactions with other policy options
<b>OPTION 1:</b> Shift the way investment costs are borne across ratepayer classes	<b>Very unhelpful:</b> Would help alleviate pressures on one part of the ratepayer base but could create significant pushback from other ratepayer classes whose costs would rise. May also result in high indirect costs to households.	
<b>OPTION 2:</b> Re-allocate costs among residential ratepayers to lower costs for low-income households	<b>Optional:</b> Can help shift costs from low-income households to higher-income ones with greater ability to pay, but could face pushback from higher-income ratepayers.	
<b>OPTION 3:</b> Governments fund a portion of system investment costs via the tax system	<b>Very helpful:</b> Status quo of recovering cost through the ratepayer base will leave them exposed to potential rate pressures. Making investments out of the tax base recognizes that aligning electricity systems with net zero has broader social benefits.	<b>Could be combined with Option 2:</b> Alleviating both overall cost pressures as well as low-income-specific ones via the broader tax base can address rate pressures and equity concerns in ways that put less of a burden on the kinds of cross-subsidization required by Option 2.  <b>Complementary with Option 4:</b> Providing general support against investment costs can help mitigate overall pressure on rates. Complementing this with targeted supports for low-income households can ensure that the costs that remain for ratepayers do not place a disproportionate burden on the households that are the least able to bear them.
<b>OPTION 4:</b> Governments provide targeted supports for low-income households	<b>Helpful:</b> Current rebates and support programs could come under increasing strain. Providing additional supports to lower-income households, funded out of the tax system, can mitigate the inequitable distribution of costs and smooth the funding of those supports across a larger population.	<b>Could be combined with Option 2:</b> Alleviating cost pressures through the ratepayer base alone fails to address them overall, but additional support, funded through the broader tax system, can spread the costs across a broader base and better mitigate pressures on ratepayers.

regions that face transitions with high investment costs, while at the same time supporting electrification and the larger political viability of the net zero transition.

### **3.4** *Challenge D: Incentives for greater interregional coordination and inerties are weak*

#### 3.4.1. The nature of the challenge

Even if the three previous challenges are successfully addressed, Canada's electricity systems would remain governed in ways that still leave weak or missing incentives for a highly cost-effective pathway to aligning Canadian electricity systems with net zero: enhanced interregional coordination and integration.

For decades, both national and international groups have called for reforms to encourage more integration and collaboration in the Canadian electricity sector. In 2016, the International Energy Agency recommended that the Government of Canada should “work with the provinces and the electricity industry to facilitate greater east-west connectivity between Canada's electricity networks and greater integration of Canada's electricity markets more generally” (IEA 2016). While Canadian electricity systems are well-connected to the United States through dozens of major transmission lines, provincial and territorial electricity systems remain largely siloed. And while some regions have seen movement on pursuing greater integration between provinces—the proposed Atlantic Loop being a prime example—little progress has been made in other regions, indicating that alternative solutions are required.

There has long been a case for greater interprovincial integration, but the imperative to decarbonize significantly amplifies the benefits of doing so. Numerous studies show that increased interregional grid connections between provinces represent a least-cost pathway for decarbonizing emissions-intensive electricity systems (Dolter and Rivers 2018; Doluweera et al. 2018; Dimanchev et al. 2020;

Rodriguez-Sarasty et al. 2020; Pineau 2021). Natural Resources Canada's Regional Electricity Cooperation and Strategic Infrastructure (RECSI) initiative also identified several interprovincial transmission projects in the West (British Columbia to Manitoba) and in the East (Atlantic region) that could reduce total system costs and emissions. In the West, six interprovincial projects out of the 25 studied in British Columbia, Alberta, Saskatchewan, and Manitoba reduced system costs and emissions at the same time (GE Energy Consulting 2018).

Interregional integration also improves economic efficiency due to the technical benefits of larger, integrated power systems. Larger systems leverage the complementarity of different provincial demand profiles and generation sources, help ease the integration of renewable resources, and enhance the reliability and resilience of systems in the face of service disruptions—which is especially important in the context of worsening climate impacts (Clark and Kanduth 2022).

In Canada, electricity is provincially regulated and system planning occurs in silos, leaving no overarching entity to enact policies and changes that ensure these benefits are realized. Instead, it is voluntary on the part of provinces and territories. So, while the imperative of decarbonization and potential support from the federal government can facilitate provincial buy-in, the provinces and territories ultimately have to decide to commit to these changes.

In some provinces and territories, policies such as self-sufficiency mandates or long-term hydropower contracts for in-province resources act as barriers to pursuing or enabling greater integration. But even in regions where these do not exist, key barriers remain, including siloed planning and operations, organizational cultures that do not value coordination, and institutional inertia.

Political opposition to enhancing interregional integration can also be a factor inhibiting greater voluntary integration. This can be driven by numerous factors, including: weak interest in cooperating with neighbouring jurisdictions due to larger inter-governmental issues and tensions; competitiveness threats posed by out-of-province producers not subject to a similar regulatory environment; a perception that grid isolation keeps jobs and investment in-province (even when it leads to higher costs for consumers); pressure from incumbent players in-province; and opposition to local impacts from new infrastructure that is not required to serve immediate provincial electricity needs.

### 3.4.2. Policy options

#### **OPTION 1: The federal government uses its convening power**

The federal government could promote and organize efforts around grid integration, including through its promised Pan-Canadian Grid Council. This could also extend to commissioning and funding studies of the benefits of greater coordination and integration and analyses of the practical steps required to achieve these goals. Such an initiative could be designed to foster greater coordination and interties between provincial and territorial systems. It could borrow some elements of its design from the Pan-Canadian Framework on Clean Growth and Climate Change (including its financial support for decarbonization for those provinces and territories that voluntarily opt-in to the framework). It could also use the existing Canadian Free Trade Agreement and its regulatory reconciliation and cooperation process as a model for managing emerging issues between provinces and territories.

The federal government's planned Pan-Canadian Grid Council is an ideal vehicle for promoting and organizing integration efforts. The Grid Council could include a number of working groups, focused not only on integration but on developing and advancing solutions to many of the common challenges provincial and territorial governments, utilities, system operators, and regulators will face in their respective efforts to align their electricity systems with net zero. (See Box 7 for more detail.) Using convening powers to encourage greater integration and coordination between electricity systems is an appropriate and uncontroversial use of federal policy tools that respects provincial and territorial jurisdiction over the electricity sector.

#### **BOX 7.**

##### *Potential composition and focus for the federal government's proposed Grid Council*

While the lack of coordination and integration across Canadian electricity systems is the most obvious symptom of siloed governance in the sector, this same issue is also witnessed by the lack of shared information and experience across different provinces' and territories' utilities, regulators, system planners, and governments.

While some information exchange of course occurs, in some policy areas it can be discretionary, informal, or irregular.

The federal government's proposed Grid Council could help to address these challenges, providing a forum to formally share experience and collaborate on shared challenges. To enhance information sharing, different working groups could be formed, with participation from, as appropriate, provincial and territorial governments, utilities, regulators and system operators, the federal government, and independent experts and groups. These working groups could focus on several possible topics, including:

- Sharing experience and developing coherent approaches for ensuring that Indigenous Peoples, governments, and organizations are able to meaningfully participate in—and lead—the transition.
- Sharing and co-developing experiments, lessons, and best practices on rate design.
- Sharing and co-developing experiments, lessons, and best practices on procurement and market design, including as it relates to non-traditional sources of supply and flexibility such as distributed energy resources, demand-side management, storage, and interregional transmission.
- Participating in studies examining the benefits of grid integration (including sharing data and vetting the methods and findings of these studies), with the scope potentially extending to U.S. states and grid authorities that were also interested in participating.
- Discussing the practical constraints to greater inter-regional grid integration and available remedies.
- Developing coherent skills and human capital strategies that can develop the labour supply required to meet the growing demand for skilled labour needed to both align electricity systems with net zero and widely deploying electrified energy end use technologies.
- Sharing experience and best practices related to the unique context and challenges of remote and off-grid communities.
- Sharing experience and best practices on working with municipalities, local distribution utilities, and consumers and other actors deploying distributed energy resources and undertaking local and regional energy planning.
- Sharing best practices and co-developing standards for data transparency and comparability.

Crafting a Grid Council with this kind of composition and focus could help overcome the limited exchange and cooperation across provincial and territorial electricity systems that can result from electricity being provincially and territorially regulated.



**OPTION 2: The federal government funds enhanced integration**

This option would have the federal government supply funding for a range of efforts to improve integration, including planning and analysis and physical infrastructure development. The federal government has already funded several transmission projects in this way. In 2013, the government signed a Federal Loan Guarantee to support the construction of the Maritime Link, a 500-MW high-voltage direct current transmission line connecting Newfoundland and Nova Scotia (Province of Nova Scotia n.d.). More recently, the Birtle transmission project, a 215-MW line between Saskatchewan and Manitoba, received \$18 million from the Green Infrastructure Stream of the Investing in Canada Infrastructure Program (Tenpenny 2020).

Federal funding for integration could be delivered in a variety of ways, including direct funding and investment tax credits. While some of the supports could involve direct outlays from the federal government, leveraged private funds could also be tapped, avoiding significant spending by the federal government (Van de Biezenbos 2021).

**OPTION 3: Provinces and territories remove informal and formal barriers to integration**

Provinces and territories exhibit a range of informal and formal barriers to regional integration and collaboration. Lifting these barriers could stimulate broader interregional collaboration on electricity sector planning and development.

On the one hand, provinces and territories face informal barriers to inter-regional integration. For example, some provinces give preference to their own domestic hydropower resources through long-term arrangements, which in essence cross-subsidize in-province consumers at the expense of out-of-province ones. These types of arrangements exist in several provinces, including British Columbia, Manitoba, Ontario, and Quebec. Since the early 2000s, Quebec has maintained a “heritage pool,” which allows Hydro Quebec to sell 165 TWh of electricity—about 90 per cent of the province’s total electricity demand—to Quebec customers at a fixed, below-market price. Any surplus energy needs are met through an open, competitive process (Hydro Quebec n.d.). These below-market rates not only foster higher levels of electricity consumption (Quebec notably has

the highest residential consumption and the lowest average cost), they also distort incentives to trade with other jurisdictions in ways that could be mutually beneficial (including for reducing emissions). In Quebec in particular, less cross-subsidization of in-province electricity consumption would free up more hydroelectricity for export to neighbouring jurisdictions, significantly reducing those jurisdictions' greenhouse gas emissions (Pineau 2012). But these long-term arrangements at below-market rates are also a means of keeping electricity bills low, and removing them may increase rates for some customers, potentially undermining political and public support for decarbonization (see Section 3.3).

On the other hand, provincial and territorial policies can also *formally* impede inter-regional integration. A clear example is through self-sufficiency mandates, such as the one currently in place in British Columbia. The province's self-sufficiency mandate requires the province to generate enough electricity in-province to theoretically meet the province's energy needs. In practice the self-sufficiency mandate does not currently prohibit inter-regional trade, as the province is in surplus. British Columbia is still able to trade a significant amount of electricity with the United States and, to a lesser extent, with Alberta.

Self-sufficiency mandates can help grow a province's domestic electricity market, which supports employment and economic development. In British Columbia, in particular, the province's self-sufficiency mandate enabled the growth of Independent Power Producers, most of which involve Indigenous participation or leadership. However, recent developments—such as the suspension of the Standing Offer Program and BC Hydro's proposed approach to renewal of Independent Power Producer agreements—have undermined these successes (Comber et al. 2022).

Removing self-sufficiency mandates would allow utilities to explore the benefits of greater integration. They could purchase clean electricity at the most affordable rates, whether within or outside provincial borders, thereby decarbonizing electricity supply at a lower cost to consumers. They could also develop generation resources domestically that complement the generation and load profiles in neighbouring jurisdictions, lowering costs for both jurisdictions. And greater integration could also support the overall reliability of supply. As the state of Texas learned during the catastrophic

storm of February 2021, isolated grids are less resilient in the face of climate-related events and disruptions (Lee 2021). Lifting these mandates could remove barriers to broader interregional collaboration on electricity sector planning and development.

**OPTION 4: Provinces and territories undertake one-off projects or planning initiatives that enhance integration and coordination**

Nordic countries (Norway, Sweden, Denmark, and Finland) did not need a supranational government to better integrate their electricity markets. Sweden adjusted its electricity market design to match the Norwegian “open” hydropower market structure, with Finland and Denmark following suit. The Norway-Denmark interties, coupled with Norway’s reservoirs, played an important role in allowing Denmark to grow its wind generation from less than 1 TWh in 1990 to more than 16 TWh in 2020, accounting now for more than 50 per cent of its generation (McCarthy 2022).

Canadian provinces and territories could similarly initiate bilateral or multilateral discussions and initiatives at their own pace to better coordinate some aspects of their electricity sectors. They could increase collaboration on integrated resource planning in order to optimize the size and location of new clean resources to align with regional potentials and transmission needs. They could expand the sharing of reserve margins, as Ontario and Quebec have done in a 500-MW summer-winter capacity exchange from 2015 to 2025. And they could ink bilateral electricity trade deals, such as the one between Newfoundland and Labrador and Nova Scotia for the Muskrat Falls hydropower development, justifying the Maritime transmission link between the two provinces. These provincial and territorial initiatives could also receive federal funding (and already have in some cases—see Option 1).

Table 8. Pros and cons of policy options

	Pros	Cons
<b>OPTION 1:</b> Using federal convening power	<ul style="list-style-type: none"> <li>Represents an effective use of federal powers that respects provincial and territorial jurisdiction over the management of electricity systems.</li> <li>Relatively low-cost option, as the costs are largely administrative.</li> <li>Represents a flexible approach, where provincial and territorial governments can determine their own levels of participation.</li> </ul>	<ul style="list-style-type: none"> <li>Without federal funds on the table, there might be limited incentive for provinces and territories to participate.</li> <li>Requires provinces, territories, and the federal government to align, to some extent, on shared objectives and vision; where this is lacking, the impact could be limited.</li> </ul>
<b>OPTION 2:</b> Federal funding for enhanced integration	<ul style="list-style-type: none"> <li>Particularly attractive for provinces and territories with thermal systems that face large-scale investments to transform their electricity systems, since better integration offers a cost-effective decarbonization pathway.</li> <li>Offers a revenue opportunity without a large investment cost for provinces and territories with hydropower, increasing their incentive to participate (though some, like Hydro-Quebec, do not want subsidized interties, as it undermines their case with US customers that they are not a publicly subsidized utility).</li> <li>Represents a flexible approach, in that provinces and territories aren't required to accept federal funding.</li> </ul>	<ul style="list-style-type: none"> <li>Non-participating provinces and territories may object to this kind of allocation of federal resources (which makes ensuring equitable opportunity of access important).</li> </ul>
<b>OPTION 3:</b> Provinces and territories remove formal and informal barriers to integration and collaboration	<ul style="list-style-type: none"> <li>Facilitates a more efficient and cost-effective use of non-emitting generation sources across Canadian electricity systems.</li> <li>Drives greater consideration of integration and builds on the experience of existing projects and infrastructure, for example between Quebec and Ontario.</li> <li>Deeper market integration would enhance trade and price fidelity across electricity markets, thereby facilitating greater inter-regional trade and optimization of resource potential.</li> </ul>	<ul style="list-style-type: none"> <li>Some will oppose the overall reliability of their power system relying in part on actions taken in a neighbouring jurisdiction, even if self-sufficiency has its own reliability challenges.</li> <li>Increased out-of-province competition could limit the role of IPPs, many of which include Indigenous communities that rely on clean energy projects for local economic development.</li> <li>Local prices could increase if provincial hydro resources are not sold at preferred historical rates, potentially undermining the case for decarbonization (see Challenge C).</li> </ul>
<b>OPTION 4:</b> Provinces and territories undertake one-off projects or planning initiatives that enhance integration	<ul style="list-style-type: none"> <li>Allows experience in working with planners and operators in other jurisdictions to build incrementally, which can help build confidence in the viability of deeper levels of integration.</li> </ul>	<ul style="list-style-type: none"> <li>Leaving it to provincial and territorial governments alone to undertake voluntary pilot projects may lead to slower results.</li> <li>If pilot projects are not well scoped, conceived and executed, the experience could deter future coordination and integration.</li> <li>Ad hoc approaches to coordination and integration could result in a network of incoherent or incompatible approaches in different parts of the country, potentially hindering greater integration in the future.</li> </ul>

### 3.4.3 Preferred solutions

**Preferred solution:**

*The federal government leverages its convening powers to encourage inter-regional integration and offers funding for projects as an incentive for participation. Provinces and territories undertake bilateral or multilateral initiatives and undergo internal reforms to enhance integration and collaboration.*

While the policy options presented here cannot solve the problem of integration and coordination entirely, they can help overcome it. They are also not mutually exclusive. Unlike the other challenges we have discussed, the preferred solution in this case may be pursuing all options simultaneously. The federal government could create a pan-Canadian platform for collaboration and integration (Option 1) and provide financial incentives for projects (Option 2). At the same time, provinces and territories could start their own internal reforms (Option 3) and bilateral or multilateral initiatives (Option 4), potentially with logistical and financial support from the federal government (Options 1 and 2). This combination of actions at multiple levels of government would accelerate integration and could serve as a series of stepping stones to longer-term, more integrated approaches (such as a regional transmission organization).

Australia's National Electricity Market provides a useful case study of regional governments spearheading integration and coordination initiatives with the support of the federal government. In 2009, the Council of Australian Governments officially formed the National Electricity Market—a single, industry-funded national energy market operator. The agreement included the enhancement and extension of interconnections among the states of New South Wales, the Australian Capital Territory, Victoria, and South Australia. The electricity market reform had strong support from both federal and state governments, though federal financial incentives ultimately played a key role in getting some states on board (KPMG 2013).

Provinces and territories should understand that it is in their best interest to integrate and coordinate with neighbouring electricity systems—for some provinces and territories, trading supplemental clean electricity offers sizable revenues, and for others, integrating with their neighbours presents cheaper pathways to net zero. Moving forward with greater interregional integration will require

that provincial and territorial governments not just understand the benefits themselves but successfully communicate these benefits to their ratepayers to secure their buy-in. This presents a unique challenge, as consumers are a diffuse and heterogeneous group that is often unfamiliar with the detailed planning and operational dimensions of electricity systems.

While there has always been an economic case for greater coordination and integration, that case is significantly strengthened by the necessity of developing net zero-aligned electricity systems that can produce fully non-emitting electricity, be flexible enough to balance the intermittency of variable renewable generation, and provide sufficient power to meet demand from increasing energy end use electrification.

*Table 9. Compatibility of policy options*

	Pros	Cons
<b>OPTION 1:</b> Using federal convening power	<b>Helpful:</b> Represents a low-cost, low-stakes option for bringing provincial and territorial governments to the table to discuss opportunities for collaboration and coordination.	
<b>OPTION 2:</b> Federal funding for enhanced integration	<b>Very helpful:</b> Federal funds can incentivize provincial and territorial action.	<b>Complementary with Option 1:</b> The promise of federal funding is a useful incentive for provinces and territories to come to the table and consider opportunities for integration.
<b>OPTION 3:</b> Provinces and territories remove formal and informal barriers to integration and collaboration	<b>Helpful:</b> Removes practical barriers to greater interprovincial trade and coordination.	<b>Complementary with Options 1 and 2:</b> Simultaneously leveraging multiple policy tools available to provincial, territorial, and federal governments can help facilitate and accelerate integration.
<b>OPTION 4:</b> Provinces and territories undertake one-off projects or planning initiatives that enhance integration and coordination	<b>Very helpful:</b> A bottom-up approach allows provinces and territories to initiate institutional arrangements at their own pace and on their own terms.	<b>Complementary with Options 1 and 2:</b> see row above. <b>Complementary with Option 3:</b> Removing formal and informal impediments to coordination is instrumental to undertaking bilateral and multilateral initiatives.



# ELECTRICITY POLICY

**4.1** The roles of federal and provincial governments in addressing key challenges

**4.2** Negotiated agreements as an accelerator

**Box 8** Federal health transfers and their conditions for receipt



# 04

## *Electricity policy in the Canadian federation*

Given shared responsibilities over environmental issues in Canada, federalism can be a complicating factor for climate change policy. But it can also present opportunities. This section examines ways to balance the tensions between decentralized and coordinated policy governance around Canada’s diverse electricity systems to enable *electric federalism*—coherent policy action from federal, provincial, and territorial governments capable of driving Canadian electricity systems toward alignment with net zero.

### **4.1** *The roles of federal and provincial governments in addressing key challenges*

Both federal and provincial/territorial orders of government have policy levers they can pull to address the four challenges we analyzed in Section 3. The implementation of specific policy options to meet a particular challenge could fall to provincial governments, to federal governments, or to both. But to address the full set of challenges and reach the goal of aligning electricity systems with net zero requires policy to be implemented by both orders of government—ideally in a coordinated fashion. The table below summarizes the roles that each order of government can play in addressing the challenges we identified in Section 3.

Table 10. **Transforming Canada's electricity systems requires policy from multiple orders of government**

Challenge	Preferred policy solutions*	Direct federal role	Direct provincial and territorial role
<b>CHALLENGE A:</b> Federal climate policy for electricity systems is misaligned with net zero	<b>OPTION A2:</b> Eliminate the current output-based carbon pricing approach ( <i>very helpful</i> )	✓	✓ (equivalency)
	<b>OPTION A3:</b> Implement a performance standard regulation ( <i>very helpful</i> )	✓	✓ (equivalency)
	<b>OPTION A4:</b> Provide tax incentives and direct subsidies ( <i>optional</i> )	✓	✓
<b>CHALLENGE B:</b> Provincial and territorial policies and institutions are not sufficiently coordinated with net zero	<b>OPTION B1:</b> Clarify the mandate of regulators to include alignment with climate goals ( <i>very helpful</i> )		✓
	<b>OPTION B3:</b> Guide the work of regulators with government energy plans and pathway assessments ( <i>very helpful</i> )		✓
	<b>OPTION B4:</b> Require that an internal carbon price be used in regulator decision-making ( <i>optional</i> )		✓
<b>CHALLENGE C:</b> Creating resilient electricity systems aligned with net zero could put upward pressure on electricity rates	<b>OPTION C2:</b> Re-allocate costs among residential ratepayers to lower costs for low-income households ( <i>optional</i> )		✓
	<b>OPTION C3:</b> Governments fund a portion of system investment costs via the tax system ( <i>very helpful</i> )	✓	✓
	<b>OPTION C4:</b> Governments provide targeted supports for low-income households ( <i>helpful</i> )	✓	✓
<b>CHALLENGE D:</b> Incentives for greater interregional coordination and interties are weak	<b>OPTION D1:</b> Using federal convening power ( <i>helpful</i> )	✓	
	<b>OPTION D2:</b> Federal funding for enhanced integration ( <i>very helpful</i> )	✓	
	<b>OPTION D3:</b> Provinces and territories remove formal and informal barriers to integration ( <i>helpful</i> )		✓
	<b>OPTION D4:</b> Provinces and territories undertake one-off projects or planning initiatives that enhance integration and coordination ( <i>very helpful</i> )		✓

\*We have excluded policy options that were identified in Section 3 as being *unhelpful*.

Because provincial and territorial governments have jurisdiction over the management of electricity systems, they are engaged in the response to all four challenges—including federal climate policy, through potential equivalency agreements. The federal government, on the other hand, has a central role in challenge A and C and a supporting role in challenge D. But addressing challenge B falls strictly to provincial governments.

### Taking a leadership role allows provincial and territorial governments to tailor their approach

Provinces and territories have a central role in transforming Canadian electricity systems because they control many of the main policy levers. Acting on all four of the challenges we have considered will allow them to transform their electricity sector with policy approaches customized to their unique regional contexts, giving them an incentive to act.

### Uncoordinated policy action runs the risk of impeding progress

Addressing all four challenges in the table above is desirable—both for individual provinces and territories and for Canada as a whole—since leaving one or more of them unresolved runs the risk of undermining the efficacy, affordability, and equity of electricity sector transformations in each of the provinces and territories. An uncoordinated approach is nonetheless feasible, leaving each order of government to act independently within its areas of respective jurisdiction. The federal government could oversee emissions reductions in the electricity sector, energy exports, and interprovincial electricity transmission, while provinces and territories could address both emissions reductions and the management of electricity systems.

Policy actions that rely on the uncoordinated, independent initiative of each government, however, may be slow to materialize. Such an approach also runs the risk of raising the overall costs of meeting Canada's near-term emissions targets, particularly the target of net zero electricity by 2035. Ultimately, uncoordinated action risks putting the achievement of broader long-term climate targets in jeopardy, as resilient, cost-effective, non-emitting electricity

systems are essential for enabling energy end-use electrification—a central pillar under every possible pathway to reaching net zero emissions (Dion et al. 2021).

The coordination challenge has both policy and political dimensions. A future federal government may choose to reverse course on federal climate policies, which could leave significant policy gaps in provinces where those policies were significant factors in their electricity sector transformations. And provinces that have not yet committed to the goal of net zero emissions may decide to move slowly on policy changes if they anticipate a change in federal government that would result in less stringent federal climate policy. These institutional incentives for provincial governments to take a wait-and-see approach risk raising the overall costs of meeting Canada's targets as well as making the attainment of those targets more difficult.

Rather than taking an uncoordinated approach, governments can create institutional incentives for coordination in a way that respects provincial and territorial jurisdiction over electricity systems. We discuss a potential model for accelerating coordinated policy action and implementation below.

## 4.2 *Negotiated agreements as an accelerator*

An approach that ties together policy actions from different orders of government in mutually supportive ways can help accelerate change. Where such an approach can cause policy action on one front to require or propel action on another, policy becomes more coordinated, and this accelerates the creation of the general policy landscape needed to transform electricity systems in line with net zero goals.

Negotiated agreements between provincial/territorial and federal governments, where they each agree to bring key policy tools to bear, could provide a means of addressing the four main challenges in electricity transformations in a coordinated fashion. This section does not define the terms of such deals with precision, as governments

themselves are best suited to do so through a negotiated process. However, we do define the broad parameters of such potential agreements and indicate how they could deliver coordinated action. We also discuss how coordination has costs as well as benefits.

### Making provincial actions a condition of federal supports could coordinate and accelerate multiple policy actions

The federal government can complement its policy efforts in the electricity sector—including carbon pricing and performance standards and support for integration—with financial supports that incentivize provincial and territorial governments to exercise their policy tools. In return for coordinated provincial and territorial policy action on electricity, the federal government could offer more stable long-term funding for provincial and territorial electricity transformations. Not only could such supports accelerate coordinated policy action to meet all four challenges, but they would also help address potential upward pressure on electricity rates (as we discussed in Section 3.3).

Federal financial supports could be made conditional on a select subset of the provincial and territorial policy actions that we describe in Section 3:

- 1. Changes to the mandates of key provincial and territorial institutions:** This would include provinces and territories mandating regulators, public utilities, and system operators to pursue development of a net zero energy system in the province through directives and/or legislation. Provinces and territories would also have to commit to giving these bodies—regulators in particular—the necessary authorities and resources to fulfill their updated mandates.
- 2. Development of energy plans and pathway assessments:** Provincial and territorial governments would commit to developing comprehensive energy plans and commissioning regular pathway assessments. Their content would be entirely at the discretion of provinces and territories so long as they were focused on developing a net zero energy system in the province or territory and provided sufficient detail.

- 3. Participation in inter-jurisdictional working groups:** This would include participation by provincial and territorial governments, regulators, and public utilities in a number of key working groups focused on knowledge exchange and identification of best practices. (See Box 7 in Section 3 for a discussion of possible working groups and the proposed Pan-Canadian Grid Council as a potential host for them.) The findings and recommendations of these working groups would remain informational and non-binding for participants.

### Negotiated agreements can offer a practical path forward in the Canadian federation

Providing financial support in exchange for meeting certain high-level conditions would be consistent with the long-standing approach taken by the federal government in another area of provincial and territorial jurisdiction: healthcare (as we explain in Box 8 below).

#### **BOX 8.**

##### *Federal health transfers and their conditions for receipt*

Healthcare is primarily an area of provincial jurisdiction, with the federal government providing significant financial contributions through the Canada Health Transfer to support the provinces in their delivery of healthcare services to the population. Healthcare is a major spending priority across Canada, with total spending rising steadily over time. According to the Canadian Institute for Health Information, total health spending in Canada is an estimated \$308 billion in 2021, or \$8,019 per Canadian, representing 12.7 per cent of Canada's GDP. The federal government contributes almost one quarter of public funding to the healthcare system.

To receive federal funding, the provinces must meet certain conditions in their design and delivery of healthcare services, as set out in the *Canada Health Act*. These include the requirements that the healthcare program be publicly administered on a non-profit basis; that it provides comprehensive and universal coverage to residents of the province; that it be portable between provinces with only a minimal waiting period for coverage; and that it be reasonably accessible to all insured persons. The Act also requires that the provinces meet certain requirements respecting the provision of information required by the federal government, and that the provinces recognize the Canada Health Transfer in public communications regarding healthcare.

This arrangement is an example of the federal government providing substantial funding in an area of provincial jurisdiction, without being overly prescriptive about how the systems should be run. Instead, high-level principles and standards must be met by the provinces in exchange for federal funding. Recent federal commitments of additional funding to address specific issues in healthcare will be delivered through partnerships and may be subject to more specific conditions, pending negotiations with the provinces on implementation.

Sources: CIHI 2021; Norris 2020; Norquay 2021.

This approach would also be consistent with federal supports for provincial childcare systems, where negotiated agreements were struck with all provinces and territories within a year of the initiative being announced.

Negotiated agreements on electricity may prove durable once they are established and funds begin to flow. Either order of government would risk significant political consequences from voters, rate-payers, and other electricity sector stakeholders if they were to withdraw from an established agreement.

### Negotiated agreements also have drawbacks

Federal financial support for provincial electricity systems would, however, come at a cost. Public funds always carry opportunity costs—additional federal support requires reduced spending on other issues, increased borrowing, or increased taxes. Provinces and territories may also push back, viewing these agreements as federal government overreach in an area of provincial jurisdiction. Provinces and territories might also see the agreement as precedent-setting, arguing that if electricity systems require federal support, other sectors do as well.

### This approach can accelerate systemic change, while respecting provincial authority over electricity

Despite the drawbacks we have noted, negotiated agreements remain a powerful tool. Some provinces may prefer their federal government supports without any ties and could even consider conditions an intrusion in an area of provincial jurisdiction. But the general conditions we have described can create a relatively

non-prescriptive role for the federal government in driving the transformation of provincial and territorial electricity systems.

Federal support would not have to be tied to any particular investment type, technology, or measure, but only to electricity system investment in general. So long as the core conditions have been met, the federal government will have assurance that its investments are supporting the development of systems in line with net zero, that there is prudent oversight and scrutiny of planned system development and capital investments, and that the benefits and merits of greater coordination and integration are receiving due consideration.

Provinces and territories, for their part, would have access to—and control over—federal funds that could help mitigate any pressure (or perceived pressure) on electricity rates. This is a significant benefit that could greatly facilitate electricity sector transformation, as pressure from households and businesses to keep electricity affordable could otherwise risk giving provincial and territorial governments pause about undertaking the significant policy changes and investments that are required to modernize their electricity systems and align them with net zero.

Finally, electricity is an exceptional case. Clean, affordable electricity can unlock emissions reductions throughout the economy; indeed, achieving Canada's emissions objectives depends on it.

Overall, electric federalism rooted in negotiated agreements with provinces would offer the federal government a way of supporting provincial and territorial electricity transitions that respects provincial and territorial jurisdiction over electricity systems and remains non-prescriptive about how they should evolve. Such agreements offer a means for the federal government to accelerate the alignment of provincial and territorial electricity systems with net zero—in a way that makes sense in the Canadian federation.





# RECOMMENDATIONS

- 5.1** Recommendations for provincial and territorial governments
- 5.2** Recommendations for the federal government

# 05

## *Recommendations*

To enable the transformation of electricity systems in ways that address the challenges discussed in Section 3, we make the following recommendations to provincial/territorial and federal governments respectively.

### **5.1** *Recommendations for provincial and territorial governments*

#### **1. Provincial and territorial governments should implement their own carbon pricing policies and performance standards in the electricity sector**

Implementing their own policies allows provincial and territorial governments to tailor their approaches to fit their unique regional contexts. Many provinces and territories have their own long-term climate commitments, and as we've shown, electricity system transformation can be a crucial engine for reaching these goals. And the non-emitting electricity generated from these initiatives will present a competitive advantage as the world shifts toward a low-carbon economy (Samson et al. 2021).

#### **2. Provincial and territorial governments should issue directives and legislation mandating that regulators, public utilities, and system operators pursue climate goals**

Provinces and territories should issue directives and legislation mandating regulators, public utilities, and system operators to pursue electricity sector development that is consistent with stated emissions

reduction targets and climate resilience. However, clarified mandates, while essential, will not be sufficient on their own because they would effectively be asking regulators to set climate policy through their decisions—an inappropriate role for an economic regulator.

### **3. Provincial and territorial governments should develop comprehensive energy plans and commission independent pathway assessments**

To enable regulators, system operators and public utilities to fulfill updated mandates that include the realization of climate targets, provincial and territorial governments should guide the work of these actors (and other, private actors) by developing comprehensive energy plans and commissioning independent pathway assessments. These plans and documents reduce policy uncertainty by providing clarity on the path forward, enabling regulators and other actors to make more informed decisions, and ensuring that they avoid making decisions that amount to effectively setting policy on their own.

Some provinces have taken steps in these directions already. For example, the government of British Columbia has issued mandate letters that task BC Hydro with assisting in the achievement of the province's climate targets. And Ontario has asked its independent system operator to assess available pathways for the phase-out of natural gas-fired generation. So far, however, no province or territory has implemented the full suite of governance reforms that we have discussed—which is critical for enabling the comprehensive, cost-effective and expedient alignment of provincial and territorial electricity systems with net zero.

Like the mandate clarifications we recommend, the provision of these kinds of guidance documents will be instrumental in aligning provincial and territorial electricity systems with net zero, and are worth pursuing on their own merits. Decisive action on these fronts can also put provinces and territories in a position to credibly claim that they are already meeting the conditions of a potential negotiated agreement with the federal government, should the federal government choose to pursue this approach (see Recommendation 9 below).

#### **4. Provinces and territories should use public funds to defray the costs of electricity system investments for ratepayers**

Aligning electricity systems with net zero may or may not increase the costs of electricity for consumers, given the rapidly declining costs of renewables and storage. Yet even perceived risks of possible increases can create barriers for governments, regulators, and utilities. To mitigate the risk of upward pressure on electricity rates, provincial and territorial governments should use funds from provincial and territorial government tax bases to defray the costs of electricity system investments to align with net zero. Provincial and territorial governments can do this across the board as well as in ways that are specifically designed to assist low-income households (which they could accomplish by strengthening their existing support programs or by creating new ones). Providing subsidies can also have pitfalls, particularly when not targeted at a clear market barrier (Ragan et al. 2017). But these challenges can be avoided when coupled with recommendations 2 and 3, which would help ensure investments defray costs for ratepayers in ways that are future-focused and cost-effective.

As we discussed above, there are strong arguments in favour of government investment in electricity systems. First, because investments focused on reducing emissions benefit society broadly, there is a case for bearing a portion of their costs broadly as well. Second, the investment is for a crucial type of public infrastructure that will only grow in importance. And third, making investments using the tax base can offer a more progressive way of sharing the cost of electricity system investments than cost recovery from ratepayers does.

Provincial and territorial governments making investments in electricity systems from the tax base is not a new concept, especially for individual projects that are large in scale. However, the kind of significant and sustained provincial and territorial government investment in electricity systems that would help meaningfully defray rate pressures going forward has been less common to date.

As a complement to using public funds to defray the costs of electricity system investments, provincial and territorial governments should direct regulators to explore new rate designs that can improve existing incentives to consume electricity, which are often weak, in ways that reflect actual system costs. This would help

maintain and improve incentives for energy efficiency, especially at times when clean power is more expensive.

## **5. Provincial and territorial governments should integrate their electricity systems**

To help realize the benefits of greater interregional integration, provincial and territorial governments should remove existing barriers to it. This can include ending formal barriers—self-sufficiency mandates, in particular—where they exist. Even where formal self-sufficiency mandates are not in place, however, there can be significant informal barriers to greater coordination and integration. Such informal barriers could include an institutional history or culture where provincial and territorial governments, utilities, or regulators have not placed a premium on the benefits of integration; incumbents with vested interests under existing arrangements that obstruct policy or initiatives that push in this direction; policies that disincentivize interregional integration and trade (such as long-term arrangements at below-market rates); and simple inertia and insufficient incentives to undertake the complex and sometimes difficult work that greater inter-governmental and inter-institutional coordination requires.

Provinces and territories can help overcome these barriers by pursuing projects or planning initiatives that enhance integration and coordination with other regional governments and electricity systems. A push from senior leadership in provincial and territorial governments, utilities, or regulators to consider and pursue the benefits of coordination and integration can help to overcome the inertia that has characterized this policy area (with notable exceptions like Atlantic Loop) across the country to date.

Provinces should also participate in the proposed Pan-Canadian Grid Council and other convening exercises to benefit from the experience and perspectives of other jurisdictions. Doing so would also position provinces and territories to demonstrate that they are already meeting the terms of a potential negotiated agreement with the federal government.

Ultimately, the provinces and territories are responsible for making the decision to coordinate and integrate their electricity systems with their neighbours. Federal policy actions can incentivize greater

cooperation, but provincial policy will be the ultimate determinant of how much will occur.

## 5.2 *Recommendations for the federal government*

### **6. The federal government should strengthen federal climate policies related to the electricity sector**

To deliver on national emissions targets, the federal government should strengthen its climate policies related to the electricity sector. In particular, the federal government should strengthen its approach to carbon pricing in the sector and implement a national performance standard for electricity.

A stronger carbon price that returns revenues to provincial and territorial ratepayers can help drive cost-effective emissions reductions in the electricity sector, while helping to keep the costs of electricity manageable for ratepayers. And because the federal carbon pricing policy would act as the benchmark for assessing whether provincial and territorial policies are equivalent, this change would ensure that provincial and territorial policies are (or become) equally strong.

This stronger carbon price should be complemented by a federal Clean Electricity Standard focussed on barring the construction of new unabated natural gas-fired generation facilities and ensuring that any remaining emissions in the sector are fully offset by 2035 with verified negative emissions. This kind of performance standard can help ensure the achievement of emissions targets more directly and effectively than a price-based instrument, while still allowing market incentives from carbon pricing to play a driving role in delivering cost-effective emissions reductions.

Together, these two federal policy measures—especially if they are combined with a hedge on carbon prices provided by the Canadian Infrastructure Bank (Beugin and Shaffer 2021)—can shore up climate policy certainty and facilitate a cost-effective transition to a net zero electricity sector by 2035.

## **7. The federal government should financially support electricity system transformations—for multiple reasons**

While interties provide a clear case for federal support, federal funds can also extend to other types of investments in the electricity sector focused on aligning systems with net zero. This could include activities that are already commonly funded by the federal government, such as research and development in clean technologies, support for large generation projects, and demonstration and deployment of smart grid technologies. Through its Smart Grid Program, for example, the federal government is investing up to \$100 million for utility-led smart grid demonstration and deployment projects. Projects are already underway in Alberta, New Brunswick, Nova Scotia, Ontario, Quebec, Prince Edward Island, Saskatchewan, and Yukon (NRCan 2022). Federal funding could also extend to more general supports for investments in electricity systems and infrastructure, but this should be conditional on high-priority provincial policy actions (as we discuss below).

Federal spending could help address fears and reduce risks regarding potential pressures on electricity rates. Making direct investments in provincial and territorial electricity systems from the federal tax base can help reduce pressure on rates and complement similar action from provincial and territorial governments. The rationale for this kind of federal investment is the same as that for provincial and territorial governments making similar investments (as we described above). Making such investments out of the federal tax base, if they are designed and allocated well, can also provide an equalizing function. This is because provinces and territories facing more costly transitions—especially those lacking in abundant hydroelectric resources and where thermal generation is currently prevalent—might very well see greater benefit from available federal supports.

Federal funding could be viewed as the flipside of the federal government's carbon pricing policy. Carbon pricing provides a "push" away from fossil fuels, while federal supports to offset the costs of electricity system investments would provide a "pull" toward an alternative energy system—one that will be vital to reaching net zero under all possible scenarios.



## **8. The federal government should leverage its convening and spending powers to encourage greater integration between provinces and territories**

While the federal government has relatively limited jurisdictional power to orchestrate greater integration and coordination of provincially and territorially managed electricity systems directly, there are concrete actions it can take to encourage progress. For one, implementing the strengthened climate policies we describe in recommendation 6 could help motivate provinces to pursue greater integration. There are also additional supportive measures it could undertake.

First, the federal government can use its convening powers to promote and organize efforts between governments related to electricity system transformation, particularly through the proposed Grid Council or similar pan-Canadian working groups. Second, the federal government can offer funding for enhanced coordination and integration, both by funding interties and by funding interprovincial projects or planning initiatives that would enhance integration and coordination.

In fact, the federal government already provides these kinds of supports. For example, the federal government committed more than \$18.7 million under the Investing in Canada Infrastructure Program to fund the Birtle Transmission Project, which allows up to 215 MW of hydroelectricity to flow from Manitoba to Saskatchewan (Manitoba Hydro 2021).

These uses of federal convening power and federal financial supports could serve as a powerful enabler of greater inter-regional coordination and integration.

## **9. The federal government should explore offering sustained, predictable financial support to provinces and territories to accelerate electricity system transformations, in exchange for certain high-level conditions being met**

To tie together the policy actions we have described in a mutually supportive way that can accelerate the transformation of electricity systems, the federal government should consider offering sustained, predictable funding to provincial and territorial governments under

negotiated agreements. The federal government should attach a limited number of high-level conditions to this potential financial support, including changes to the mandates of key provincial and territorial institutions, the development of comprehensive energy plans and independent pathway assessments, and participation in inter-jurisdictional working groups.

These financial agreements could be negotiated between each province or territory and the federal government individually. This approach acknowledges that some provinces may be quicker than others to sign on (especially where they have taken decisive early action on these fronts), and that the level of supports may differ among provinces and territories, since each jurisdiction faces different opportunities and challenges on the path to net zero.

Ultimately, this approach offers a way for the federal government to enable and accelerate the transformation of provincial and territorial electricity systems in a way that makes sense in the Canadian federation. If the federal government is serious about achieving net zero in the electricity sector by 2035 and in the economy as a whole by 2050, it should begin exploring this approach immediately and consider making it a key plank of its Budget 2023.



# ANNEX

## *Stakeholder consultations*

We wish to acknowledge the input and guidance we received during our engagement with a broad range of stakeholders, including:

Alberta Innovates	Canadian Renewable Energy Association	Energy and Materials Research Group at Simon Fraser University
Alberta Utilities Commission	Capital Power Corporation	ENMAX
Algonquin Power & Utilities Corp.	Charlottetown Chamber of Commerce	ESMIA Consultants
AltaLink	City of Charlottetown	Environment and Climate Change Canada
Asia Pacific Economic Corporation	City of Halifax	Federation of Prince Edward Island Municipalities
Association of Municipalities of Ontario	City of Medicine Hat	First Nations Power Authority
Association québécoise pour l'énergie renouvelable	City of Saskatoon	Fortis BC
ATCO	City of St. John's	General Electric Canada
Atlantic Canada Opportunities Agency	City of Toronto	Government of Alberta
Atlantic Chamber of Commerce	City of Vancouver	Government of British Columbia
Atlantic Policy Congress of First Nations Chiefs Secretariat	City of Winnipeg	Government of Manitoba
Atlantic Provinces Economic Council	Clean Energy BC	Government of New Brunswick
Atlantica Center for Energy	Clean Energy Canada	Government of Newfoundland and Labrador
Baffin Regional Chamber of Commerce	Clean Foundation	Government of Northwest Territories
BC Hydro	Climate Change Connection	Government of Nova Scotia
British Columbia Utilities Commission	Community Energy Association	Government of Nunavut
Business Council of British Columbia	Conboy Advisory Services	Government of Ontario
C.D. Howe Institute	Council of Yukon First Nations	Government of Prince Edward Island
CAMPUT: Canada's Utility and Energy Regulators	Counsel Public Affairs	Government of Quebec
Canada Energy Regulator	Cowesses Ventures	Government of Saskatchewan
Canada Grid	David Suzuki Foundation	Government of Yukon
Canadian German Chamber of Industry and Commerce	Delphi Group	Greengate Power
Canadian Nuclear Association	Dunsky Energy Consulting	Heartland Generation
	Ecology Action Centre	Heritage Gas
	Ecotrust Canada	Hydro One
	Efficiency Canada	Hydro Quebec
	Efficiency One	
	Electric Power Research Institute	
	Electricity Canada	
	Emissions Reduction Alberta	

International Institute for Sustainable Development	Newfoundland Power	Reshape Infrastructure Strategies
Indigenous Clean Energy	Newfoundland and Labrador Hydro	Rural Municipalities of Alberta
Industrial Gas Users Association	Northwest Territories Association of Communities	Saint John Energy
Island Regulatory and Appeals Commission	Northland Power	SaskPower
Kanaka Bar Indian Band	Northwest Territories Power Corporation	Saskatchewan Chamber of Commerce
Keppel Gate Consulting	Nova Scotia Power	Saskatchewan Environmental Society
Kisik Clean Energy	Nova Scotia Utility and Review Board	Saskatchewan Urban Municipalities Association
Kolesar Buchanan & Associates Ltd.	NS Power	Saskatoon Light and Power
Manitoba Environmental Industries Association	NS Utility & Review Board	Saskatchewan Rate and Review Panel
Manitoba Hydro	Ofgem	Sawridge First Nation
Manitoba Public Utilities Board	Ontario Chamber of Commerce	Smart Grid Innovation Network
Maritime Electric Company	Opportunities New Brunswick	Sustainable Energy Systems Integration & Transitions Group
Maritimes Energy Association	Ontario Energy Board	Sustainable Waterloo Region
Metro Vancouver	Ontario Power Generation	Toronto and Region Board of Trade
Nunastsiavut Government	Opportunities New Brunswick	Toronto and Region Conservation Authority
Nalcor	Pacific Institute for Climate Solutions	Toronto Atmospheric Fund
National Farmers Union - Region 6	PEI Energy Corporation	Town of Canmore
Natural Forces	Pembina Institute	Town of Digby
Natural Resources Canada	Polaris Strategy + Insight	TransAlta
Navius Research	Power Advisory LLC	Transition Accelerator
NB Power	Powerconsumer Inc.	Trottier Energy Institute
New Brunswick Energy and Utilities Board	Prairie Climate Centre	Toronto and Region Conservation Authority
New Brunswick Energy Marketing Corporation	Propulsion Quebec	Toronto Hydro
New Relationship Trust	Qikiqtaaluk Corporation	Waterpower Canada
Newfoundland and Labrador Board of Commissioners	Qikiqtani Inuit Association	Wind Energy Institute of Canada
Newfoundland and Labrador Environmental Industry Association	Quebec Business Council on the Environment	Wrangellia Consulting
	Quebec Net Positive	
	QUEST	
	Régie de l'énergie du Québec	
	Region of Durham	

*We also wish to acknowledge the valuable input provided by individual experts, academics, and practitioners.*

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SYSTEMS WITH NET ZERO

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